**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY**
**AIR QUALITY DIVISION**

**MEMORANDUM** **June 26, 2013**

**TO:** Phillip Fielder, P.E., Permits and Engineering Group Manager

**THROUGH:** Phil Martin, P.E., Manager, Existing Source Permits Section

**THROUGH:** Peer Review

**FROM:** Charles Stockford, P.E., Existing Source Permits Section

**SUBJECT:** Evaluation of Permit Application No. **2008-302-C (M-1) PSD**
Western Farmers Electric Cooperative
Mooreland Generating Station (SIC 4911)
SW/4 of Section 27-T23N-R19W, Woodward County
Location: Corner of Highways 412 & 50, 1 mile West of Mooreland

## SECTION I. INTRODUCTION

Western Farmers Electric Cooperative (WFEC) has requested a construction permit for their Mooreland Generating Station (SIC 4911). The facility is currently operating under Permit No. 2008-302-TVR2 issued March 4, 2009. The initial Title V operating permit was issued on October 5, 1998.

WFEC submitted a Prevention of Significant Deterioration (PSD) construction permit application for the proposed addition of a combined-cycle combustion turbine and associated support equipment to the existing Mooreland Generating Station located 1.2 miles west of Mooreland, Oklahoma. The Mooreland Unit 4 Combined Cycle Project, hereinafter referred to as Project, will be a single 360 megawatt (MW), nominal, combustion turbine that will include one F-class combustion turbine (with two different vendor options for the combustion turbine as WFEC has not selected the manufacturer), one heat recovery steam generator (HRSG) with duct firing and one steam turbine. The Mooreland Unit 4 combustion turbine will be designed to burn pipeline-quality natural gas only. In addition to the Mooreland Unit 4 combustion turbine, a cooling tower (which will be slightly different for each combustion turbine option), emergency diesel generator, and fuel oil storage tank will also be included as part of the Project.

This PSD air construction permit application includes consideration of two combustion turbine options:

- **GE Option:** One General Electric (GE) 7FA.05 class natural gas-fired combustion turbine generator with an 820.5 million British thermal units per hour (MMBtu/hr) duct burner in a HRSG that provides steam to a steam turbine generator

- **Siemens Option**: One Siemens SGT6-5000F5 class natural gas-fired combustion turbine generator with an 820.3 MMBtu/hr duct burner in a HRSG that provides steam to a steam turbine generator

This permit contains the following analyses/assessments regarding emissions of regulated pollutants associated with the construction and operation of the Project at the Mooreland Generating Station:

- Evaluation of ambient air quality in the area for each regulated pollutant for which the Project will result in a significant net emissions increase,
- Demonstration that emissions increases resulting from the Project will not cause or contribute to an increase in ambient concentrations of pollutants exceeding the remaining available PSD increment and the National Ambient Air Quality Standards (NAAQS),
- Assessment of any adverse impacts on soils, vegetation, visibility, and growth in the area, and
- A Best Available Control Technology (BACT) analysis for each regulated pollutant for which the Project will result in a significant net emissions increase.

Since the Mooreland Generating Station emits more than 100 TPY of a regulated pollutant, it is subject to Title V permitting requirements. Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) in the following outline. Pipeline-grade natural gas is the primary fuel with the boilers being operated continuously.

## SECTION II. FACILITY DESCRIPTION

WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFEC's system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers that burn locally-produced natural gas. The three high-pressure boilers used to generate electricity and the auxiliary boiler used to heat the facility were constructed before May 31, 1972, and are considered "grandfathered" from construction permitting requirements.

The generators are peaking units which operate only when it is economically feasible, such as during peak demand. However, the potential emissions listed in the emissions table are based on continuous operation of all units.

Emission units have been arranged into Emission Unit Groups (EUGs) with EUG A being the proposed turbine and existing boilers, EUG B being existing equipment, EUG C being the condensate and diesel tanks and EUG D being the cooling towers. There is only one significant operating scenario for the facility. For this scenario, the boilers, turbine and the facility space heating boiler burn natural gas.

## SECTION III. EQUIPMENT

**EUG A1 Non-Grandfathered Boiler/Turbine Equipment List**

| Point (EUG-EU) | Manufacturer | MMBTUH | KW | Serial Number | Construction Date |
|---|---|---|---|---|---|
| A-3 | Riley Stoker Boiler | 1,755 | 135,000 | 3769 | 1971 |
| A-4 | GE or Siemens Turbine with HRSG and Duct Burner | 3,300 | 360,000 | TBD | TBD |

**EUG A2 Grandfathered Boiler Equipment List**

| Point (EUG-EU) | Manufacturer | MMBTUH | KW | Serial Number | Construction Date |
|---|---|---|---|---|---|
| A-1 | Babcock & Wilcox Boiler | 756 | 44,000 | 21171 | 1963 |
| A-2 | Riley Stoker Boiler | 1,620 | 125,000 | 3515 | 1966 |

**EUG B General Equipment List**

| Point (EUG-EU) | Manufacturer | MMBTUH | KW | Serial Number | Construction Date |
|---|---|---|---|---|---|
| B-1* | Small Bldg. Heater | <5.0 | NA | | |
| B-2* | Erie City Iron Works | 2.41 | NA | 96006 | 1963 |
| B-3 | Emergency Gen. | - | 1,000 | TBD | TBD |
| B-4 | Emer. Fire Pump | - | 300-hp | 11482389 | 1987 |

***** These units qualify as insignificant activities, since they have rated heat inputs below 5 MMBTUH.

**EUG C Storage Tanks**

| Point (EUG-EU) | Contents | Capacity (barrels) | Annual Throughput (barrels) |
|---|---|---|---|
| C-6 | Condensate | 100 | 500 total all four tanks |
| C-7 | Condensate | 190 | |
| C-8 | Condensate | 300 | |
| C-9 | Condensate | 300 | |
| C-10 | Diesel | 66.7 | TBD |

**EUG D Cooling Towers**

| Point (EUG-EU) | Vendor | Capacity | Installation Date |
|---|---|---|---|
| D-1 | Midwest Towers | - | 1963 |
| D-2 | Midwest Towers | - | 1963 |
| D-3 | Midwest Towers | - | 1963 |
| D-4 | TBD | TBD | TBD |

| Stack Parameters | | | | |
|---|---|---|---|---|
| **Point (EUG-EU)** | **Height (feet)** | **Diameter (feet)** | **Flow (ACFM)** | **Temperature (°F)** |
| A-1 | 125 | 10.0 | 147,000 | 250 |
| A-2 | 153 | 12.0 | 392,000 | 220 |
| A-3 | 154 | 12.0 | 451,000 | 252 |
| A-4 | 130 | 22.0 | 59.2 ft/s* | 193 |
| B-2 | 45 | 0.5 | 542 | 425 |
| B-3 | 15 | 0.67 | - | - |
| B-4 | 47.6 | 1.6 | - | - |

***Based on the Siemens combustion turbine**

## SECTION IV. EMISSIONS

The basis for the following proposed Turbine emissions estimates are discussed in further detail under the "GE Option Combustion Turbine Emissions" and the "Siemens Option Combustion Turbine Emissions" sections.

Project Emissions in the below (2) tables consist of combustion turbine emissions (including startup and shutdown emissions), duct burner, emergency diesel generator, fuel oil storage tank and cooling tower emissions.

### GE and Siemens Emissions Comparison

**GE Option - Project Emissions and PSD Significance Levels**

| **Pollutant[A]** | **Preliminary Estimated GE Option Project Potential Emissions (Tons per Year)[B]** | **PSD Significance Levels (Tons per Year)** |
|---|---|---|
| $NO_X$ | **201.1** | 40 |
| CO | **334.5** | 100 |
| $SO_2$ | 39.4 | 40 |
| VOC | **98.2** | 40 |
| PM/ $PM_{10}$[C]/ $PM_{2.5}$[C] | **144.2** | 25/15/10 |
| $CO_2e$ | **1,703,928** | 75,000 |
| $H_2SO_4$ Mist | 6.0 | 7 |
| Lead | $1.8 \times 10^{-3}$ | 0.6 |

[A] $NO_x$ = nitrogen oxides; CO = carbon monoxide; $SO_2$ = sulfur dioxide; VOC = volatile organic compounds; PM= total particulate matter; $PM_{10}$ = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; $CO_2e$ = carbon dioxide equivalent (greenhouse gases); $H_2SO_4$ Mist = sulfuric acid mist
[B] Numbers in **bold** indicate the PSD significance level is exceeded
[C] Filterable plus condensable

**Siemens Option - Project Emissions and PSD Significance Levels**

| Pollutant | Preliminary Estimated Siemens Option Project Potential Emissions (Tons per Year)[A] | PSD Significance Levels (Tons per Year) |
|---|---|---|
| $NO_X$ | **204.0** | 40 |
| CO | **336.3** | 100 |
| $SO_2$ | 39.0 | 40 |
| VOC | **98.4** | 40 |
| PM/ $PM_{10}$[B]/ $PM_{2.5}$[B] | **144.2** | 25/15/10 |
| $CO_2e$ | **1,771,523** | 75,000 |
| $H_2SO_4$ Mist | 6.0 | 7 |
| Lead | $1.8 \times 10^{-3}$ | 0.6 |

[A] Numbers in **bold** indicate the PSD significance level is exceeded
[B] Filterable plus condensable

**GE Option Combustion Turbine Emissions**

Emissions from the combustion turbine are dependent on ambient temperature conditions and the turbine's operating load, which can vary from 50 percent to 100 percent. To account for representative seasonal climatic variations, potential emissions from the proposed combustion turbine were analyzed at 50, 75, and 100 percent load conditions for ambient temperatures ranging from negative (-)24 degrees Fahrenheit (°F) to 115°F. The projected emissions were based on data provided by the combustion turbine manufacturer (GE) and/or from AP-42 emission factors. Detailed calculations of the combustion turbine's emissions are provided in Appendix C of the application.

The following conservative assumptions were used to determine potential emissions for the GE Option:

- Start-up and shut down emissions were based on the start-up and shutdown profiles for the combined cycle combustion turbine (assumes a maximum of four (4) hours per start-up and one (1) hour per shutdown) and 365 start-ups and 365 shut downs per year
- CO emissions were based on the vendor's guaranteed emissions rate of 2 parts per million (ppmvd @ 15% $O_2$); and 14.0 pound per hour (lb/hr) for loads of 50 percent and greater.
- $PM/PM_{10}/PM_{2.5}$ emissions were based on an estimated maximum emission rate of 31.8 lb/hr (including while duct firing) while operating in combined-cycle mode.
- $NO_x$ emissions were based on the manufacturer's guaranteed emission rate of 2 ppmvd @ 15% $O_2$; and 23.0 lb/hr for loads of 50 percent and greater.
- $SO_2$ emissions were based on the sulfur content of pipeline quality natural gas and an estimated maximum emission rate of 9 lb/hr (including while duct firing) while operating in combined-cycle mode.
- VOC emissions were based on an estimated maximum emission rate of 5 ppmvd @ 15% $O_2$; and 17.0 lb/hr for loads of 50 percent and higher.

- $CO_2e$ emissions were based on AP-42 emission factors plus a 10 percent degradation safety factor for $CO_2$, methane ($CH_4$) and nitrous oxide ($N_2O$), and ratioed with their appropriate global warming potentials (GWP) and summed to obtain $CO_2e$

Based on the above assumptions, the maximum expected hourly emission rates for normal operation (excluding start-up and shutdown) for the combustion turbine under the GE Option are shown in the following table.

**GE Option - Maximum Expected Hourly Emission Rates for Normal Operation (lb/hr)[A]**

| Source Description | $NO_X$ | CO | PM/ $PM_{10}$/ $PM_{2.5}$ | VOC | $SO_2$ | $H_2SO_4$ Mist | $CO_2e$ | Lead |
|---|---|---|---|---|---|---|---|---|
| GE Option 7FA Gas Turbine | 23.0 | 14.0 | 31.8 | 17.0 | 9.0 | 1.38 | 389,006 | $4.0 \times 10^{-4}$ |

[A] Normal operation excludes start-up and shut down operations. Emissions include duct firing emissions.

**GE Option Combustion Turbine Start-Up and Shut Down Emissions**

Potential start-up and shut down emissions were based on a start-up profile and it was conservatively assumed there would be 365 start-ups and 365 shut downs per year. Start-up is defined as 0 to 50 percent load and shut down is defined as 50 to 0 percent load. Start-up is assumed to take no more than four hours and shut down is assumed to take no more than one hour. Potential start-up and shut down emissions for the GE Option are shown below. Detailed calculations of the potential start-up and shut down emissions are provided in Appendix C of the application.

**GE Option - Potential Start-up and Shut Down Emissions**

| Pollutant | Number of Start-ups and Shut Downs per Year[A] | lb/Start-up | lb/Shut Down | Total Start-up and Shut Down Emissions (Tons per Year) |
|---|---|---|---|---|
| $NO_x$ | 365 | 573.2 | 48.3 | 113.4 |
| CO | 365 | 1,363.4 | 151.1 | 281.3 |
| PM/$PM_{10}$/$PM_{2.5}$ | 365 | 66.9 | 6.6 | 13.4 |
| VOC | 365 | 162.8 | 23.5 | 34.0 |
| $SO_2$ | 365 | 22.2 | 2.0 | 4.1 |
| $H_2SO_4$ Mist | 365 | 3.1 | 0.3 | 0.62 |
| $CO_2e$ | 365 | 1,176,743.6 | 116,701.8 | 236,054 |
| Lead | 365 | -- | | -- |

[A] 365 start-ups and 365 shut downs per year.

**Siemens Option Combustion Turbine Emissions**

As mentioned above, emissions from the combustion turbine are dependent on the ambient temperature conditions and the turbine's operating load, which can vary from 50 percent to 100 percent. As with the GE Option, potential emissions under the Siemens Option were analyzed at 50, 75, and 100 percent load conditions for ambient temperatures ranging from negative (-)24 °F to 115°F. The projected emissions were based on data provided by the combustion turbine manufacturer (Siemens) and/or from AP-42 emission factors. Detailed calculations of the combustion turbine's emissions are provided in Appendix C of the application.

The following conservative assumptions were used to determine potential emissions for the Siemens Option:

- Start-up and shut down emissions were based on the start-up and shutdown profiles for a combined cycle combustion turbine (assumes a maximum of four (4) hours per start-up and one (1) hour per shutdown) and 365 start-ups and 365 shut downs per year
- CO emissions were based on the vendor's guaranteed emissions rate of 2 ppmvd @ 15% $O_2$; and 14.5 lb/hr for loads of 50 percent and greater
- $PM/PM_{10}/PM_{2.5}$ emissions were based on an estimated maximum emission rate of 31.6 lb/hr (including while duct firing) while operating in combined-cycle mode.
- $NO_x$ emissions were based on the manufacturer's guaranteed emission rate of 2 ppmvd @ 15% $O_2$; and 23.8 lb/hr for loads of 50 percent and greater.
- $SO_2$ emissions were based on the sulfur content of pipeline quality natural gas and an estimated maximum emission rate of 8.9 lb/hr (including while duct firing) while operating in combined-cycle mode.
- VOC emissions were based on an estimated maximum emission rate of 5 ppmvd @ 15% $O_2$; and 17.0 lb/hr for loads of 50 percent and higher.
- $CO_2e$ emissions were based on AP-42 emission factors plus a 10 percent degradation safety factor for $CO_2$, $CH_4$ and $N_2O$, and ratioed with their appropriate GWP and summed to obtain $CO_2e$.

Based on the above assumptions, the maximum expected hourly emission rates for normal operation (excluding start-up and shutdown) for the combustion turbine under the Siemens Option are shown in the following table.

**Siemens Option – Max. Expected Hourly Emission Rates for Normal Operation (lb/hr)[A]**

| Source Description | $NO_X$ | CO | $PM/PM_{10}/PM_{2.5}$ | VOC | $SO_2$ | $H_2SO_4$ Mist | $CO_2e$ | Lead |
|---|---|---|---|---|---|---|---|---|
| Siemens Option SGT6-5000F5 Gas Turbine | 23.8 | 14.5 | 31.6 | 17.0 | 8.9 | 1.36 | 404,439 | $4.0 \times 10^{-4}$ |

[A] Normal operation excludes start-up and shut down operations. Emissions include duct firing emissions.

**Siemens Option Combustion Turbine Start-Up and Shut Down Emissions**

Potential start-up and shut down emissions were based on a start-up profile and it was conservatively assumed that there will be 365 start-ups and 365 shut downs per year. Start-up is defined as 0 to 50 percent load and shut down is defined as 50 to 0 percent load. Start-up is assumed to take a maximum of four hours and shut down is assumed to take a maximum of one hour. Potential start-up and shut down emissions for the Siemens combustion turbine are shown below. Detailed calculations of the potential start-up and shut down emissions are provided in Appendix C of the application.

**Siemens Option - Potential Start-up and Shut Down Emissions**

| Pollutant | Number of Start-ups and Shut Downs per Year[A] | lb/Start-up | lb/Shut Down | Total Start-up and Shut Down Emissions (Tons per Year) |
|---|---|---|---|---|
| $NO_x$ | 365 | 573.2 | 48.3 | 113.4 |
| CO | 365 | 1,363.4 | 151.1 | 281.3 |
| $PM/PM_{10}/PM_{2.5}$ | 365 | 67.1 | 6.7 | 13.5 |
| VOC | 365 | 162.8 | 23.5 | 34.0 |
| $SO_2$ | 365 | 22.4 | 2.0 | 4.1 |
| $H_2SO_4$ Mist | 365 | 3.1 | 0.3 | 0.63 |
| $CO_2e$ | 365 | 1,223,427 | 121,332 | 245,419 |
| Lead | 365 | -- | | -- |

[A] 365 start-ups and 365 shut downs per year.

A-1 through A-3 boiler emissions estimates reflect continuous operation with emission rates based on AP-42 (7/98), section 1.4 for both criteria pollutants and toxic pollutants, except for NOx emissions, which are the emissions used for modeling compliance with the NAAQS. Emissions associated with the small building heater and the Erie City Iron Works boiler (B-1 and B-2, respectively) are considered negligible. Emissions associated with the emergency generator (B-3) are estimated based on NSPS emission rates for PM, $PM_{10}$, and $PM_{2.5}$, while all other pollutant emissions are estimated using AP-42 emission factors and assume operation of 100 hours per year for testing and maintenance. Emission associated with the diesel fire water pump (B-4) are estimated based on AP-42 and assume operation of 100 hours per year for testing and maintenance. Emissions associated with the storage tanks (C-6 through C-10) are estimated based on EPA TANKS emission software. Emissions associated with the cooling towers (D-1 through D-4) are estimated based on AP-42 and assume continuous operation.

| Total Facility Emissions* | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | $NO_X$ | | CO | | VOC | | $PM_{10}$ | | $SO_2$ | |
| **EU** | **lb/hr** | **TPY** | **lb/hr** | **TPY** | **lb/hr** | **TPY** | **lb/hr** | **TPY** | **lb/hr** | **TPY** |
| A-1 | 207.5 | 908.9 | 62.3 | 272.7 | 4.1 | 17.9 | 5.6 | 24.7 | 38.90 | 170.4 |
| A-2 | 444.7 | 1947.8 | 133.4 | 584.3 | 8.7 | 38.3 | 12.1 | 52.9 | 83.35 | 365.1 |
| A-3 | 351.0 | 1537.4 | 144.5 | 633.0 | 9.5 | 41.5 | 13.1 | 57.3 | 90.29 | 395.5 |
| A-4a | 23.0 | 200.2 | 14.0 | 334.5 | 17.0 | 98.2 | 31.8 | 144.2 | 9.0 | 39.4 |
| A-4b | 23.8 | 203.1 | 14.5 | 336.3 | 17.0 | 98.4 | 31.6 | 144.2 | 8.9 | 39.0 |
| B-3 Gen. | -- | 0.71 | -- | 0.37 | -- | -- | -- | -- | -- | -- |
| B-4 Fire-P. | -- | 5.00 | -- | 1.00 | -- | -- | -- | -- | -- | -- |
| C-6 – C-10 Tanks | -- | -- | -- | -- | 0.4 | 1.7 | -- | -- | -- | -- |
| D-1 – D-4 Cooling Towers | — | — | — | — | — | — | 2.42 | 10.6 | — | — |
| **TOTAL** | **1,026.2** | **4,494.8** | **353.6** | **1,563.8** | **42.8** | **246.8** | **63.8** | **271.1** | **221.4** | **970.4** |

*Either A-4a or A-4b will be constructed. A-4a turbine emissions estimates are based on the discussion above for the GE version, while A-4b turbine emissions estimates are based on the discussion above for the Siemens version. Lb/hr emission rates do not include start-up and shutdown emissions. TPY emissions include both start-up and shutdowns as well as normal operation.

A-1 through A-3 boiler emissions estimates reflect continuous operation with emission rates based on AP-42 (7/98), section 1.4 for both criteria pollutants and toxic pollutants, except for NOx emissions, which are the emissions used for modeling compliance with the NAAQS.

**HAP EMISSIONS**

| Pollutant | C A S Number | Emissions (TPY) | |
|---|---|---|---|
| | | Existing | Total w/Project |
| 2-Methylnapthalene | 97-57-6 | 4.3E-04 | 5.1E-04 |
| 3-Methylchloranthrene | 56-49-5 | 3.2E-05 | 3.8E-05 |
| 7,12-Dimethylbenz(a)anthracene | | 2.8E-04 | 3.4E-04 |
| Acenapthalene | 203-96-8 | 3.2E-05 | 4.3E-05 |
| Acetaldehyde | 75-07-0 | 4.3E-04 | 4.1E-01 |
| Acrolein | 107-02-8 | 5.1E-05 | 6.6E-02 |
| Anthracene | 120-12-7 | 4.3E-05 | 5.2E-05 |
| Benz(a)anthracene | 56-55-3 | 3.2E-05 | 3.9E-05 |
| Benzene | 71-43-2 | 3.8E-02 | 1.7E-01 |
| Benzo(a)pyrene | 50-32-8 | 2.1E-05 | 2.6E-05 |
| Benzo(b)flouranthene | 205-99-2 | 3.2E-05 | 3.9E-05 |
| Benzo(g,h,l,)perylene | 191-24-2 | 2.1E-05 | 2.6E-05 |
| Benzo(k)flouranthene | 205-82-3 | 3.2E-05 | 3.8E-05 |
| 1,3-Butadiene | 106-99-0 | 2.2E-05 | 4.5E-03 |
| Chrysene | 218-01-9 | 3.2E-05 | 3.9E-05 |
| Dibenzo(a,h)anthracene | 53-70-3 | 2.1E-05 | 2.6E-05 |
| Dichlorobenzene | 25321-22-6 | 2.1E-02 | 2.6E-02 |
| Ethylbenzene | 100-41-4 | 0.0E+00 | 3.3E-01 |
| Fluoranthene | 206-44-0 | 5.3E-05 | 6.6E-05 |
| Fluorene | 86-73-7 | 5.0E-05 | 6.6E-05 |

| | | | |
|---|---|---|---|
| Formaldehyde | 500-00-0 | 1.3E+00 | 3.7E+00 |
| Hexane | 110-54-3 | 8.0E-03 | 8.8E-03 |
| Indeno(1,2,3-cd)pyrene | 193-39-5 | 3.2E-05 | 3.8E-05 |
| Naphthalene | 91-20-3 | 1.1E-02 | 2.7E-02 |
| PAH | | 0.0E+00 | 2.3E-02 |
| Phenanatharene | 85-01-8 | 3.0E-04 | 3.8E-04 |
| Proplylene Oxide | 75-56-9 | 0.0E+00 | 3.0E-01 |
| Pyrene | 129-00-0 | 8.9E-05 | 1.1E-04 |
| Toluene | 108-88-3 | 6.1E-02 | 1.4E+00 |
| Xylene | 1330-20-7 | 1.6E-04 | 6.6E-01 |
| **TOTALS** | | **1.47** | **7.14** |

## HAP EMISSIONS

The Project is a minor source of Hazardous Air Pollutants (HAPs) (less than 25 tons per year of total HAPs and less than 10 tons per year of any single HAP) for either the GE or the Siemens Option. In addition, the existing Mooreland Generating Station is currently classified as an area source of HAPs and will remain an area source of HAPs since the total emissions from the existing facility plus the Project will remain below the thresholds of 25 tons per year of total HAPs and 10 tons per year of any single HAP.

## SECTION V. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS (BACT)

OAC 252:100-8-34(b)(2) requires the application of BACT for each regulated NSR pollutant for which a significant net emissions increase will be realized as a result of the modification. As indicated in Section IV Emissions, the Project is subject to PSD review for $NO_x$, CO, $PM/PM_{10}/PM_{2.5}$, VOC, and $CO_2e$. Therefore, a BACT analysis was performed for each of these regulated NSR pollutants.

WFEC is proposing to modify the existing Mooreland Generating Station by constructing one new combustion turbine, a HRSG with duct firing, an emergency diesel generator, a cooling tower, and a diesel fuel oil storage tank. The combustion turbine (A-4) will be operated solely in combined-cycle mode and will be permitted for 8,760 hours per year. The combustion turbine will burn natural gas exclusively. This section describes the BACT analysis for all new equipment proposed for the Project.

The Project will include one F-class combustion turbine, one HRSG with duct firing, and one steam turbine. The combustion turbine will be one of the following:

- A GE 7FA.05 combustion turbine with a nominal output of 204 MW.[1] The HRSG will be complete with duct firing (maximum heat input of 820.5 MMBtu/hr) and, with the steam turbine, the overall estimated output will be a nominal 300 MW (approximately 388 MW maximum, gross, at full capacity and fully fired).
- A Siemens SGT6-5000F5 combustion turbine with a nominal output of 232 MW.[2] The HRSG will be complete with duct firing (maximum heat input of 820.3 MMBtu/hr) and,

[1] At 59 °F and 100 percent load
[2] At 59 °F and 100 percent load

with the steam turbine, the overall estimated output will be a nominal 350 MW (approximately 410 MW maximum, gross, at full capacity and fully fired).

The BACT analysis was performed using the "top-down" approach, which is described below. A summary of the BACT emission limits and the associated control technologies for the GE Option combustion turbine are shown in Table 5-1A. Table 5-1B shows the BACT emission limits and associated control technologies for the Siemens Option combustion turbine. BACT emission limits and associated control technologies for the auxiliary equipment are listed in Table 5-2.

**Table 5-1A. GE Option - Summary of BACT Results – Combustion Turbine**

| Equipment | Pollutant | Control | BACT Emission Rate | Averaging Period |
|---|---|---|---|---|
| GE Option - Natural Gas-Fired Combined Cycle Combustion Turbine with Duct Burner | $NO_x$ | Low $NO_x$ Burners<br>SCR | 2 ppmvd[A]<br>23.0 lb/hr[B] | 30-day |
| | CO | Oxidation Catalyst | 2 ppmvd[A]<br>14.0 lb/hr[B] | 3-hour |
| | $PM/PM_{10}/PM_{2.5}$ | Combustion Controls<br>Low Ash Fuels | 31.8 lb/hr[B] | 3-hour |
| | VOC | Oxidation Catalyst | 17.0 lb/hr[B] | 30-day |
| | Greenhouse Gases | Use of natural gas as a fuel,<br>Monitoring and control of excess air<br>Efficient turbine design | 1,000 lb/MW-hr $CO_2$ | Annual |

[A] Concentration at 15 percent oxygen while operating at greater than 50 percent load. [B] Emission rate at loads of 50 percent and higher

**Table 5-1B. Siemens Option - Summary of BACT Results – Combustion Turbine**

| Equipment | Pollutant | Control | BACT Emission Rate | Averaging Period |
|---|---|---|---|---|
| Siemens Option - Natural Gas-Fired Combined Cycle Combustion Turbine with Duct Burner | $NO_x$ | Low $NO_x$ Burners<br>SCR | 2 ppmvd[A]<br>23.8 lb/hr[B] | 30-day |
| | CO | Oxydation Catalyst | 2 ppmvd[A]<br>14.5 lb/hr[B] | 3-hour |
| | $PM/PM_{10}/PM_{2.5}$ | Combustion Controls<br>Low Ash Fuels | 31.6 lb/hr[B] | 3-hour |
| | VOC | Oxidation Catalyst | 17.0 lb/hr[B] | 30-day |
| | Greenhouse Gases | Use of natural gas as a fuel,<br>Monitoring and control of excess air<br>Efficient turbine design | 1,000 lb/MW-hr $CO_2$ | Annual |

[A] Concentration at 15 percent oxygen while operating at greater than 50 percent load. [B] Emission rate at loads of 50 percent and higher

**Table 5-2. Summary of BACT Results – Auxiliary Equipment**

| Equipment | Pollutant | Control | BACT Emission Rate |
|---|---|---|---|
| Diesel Generator | $NO_x$ | Combustion Control | 0.011 pound per horsepower-hour (lb/hp-hr) |
| | CO | Combustion Control | 0.006 lb/hp-hr |
| | $PM/PM_{10}/PM_{2.5}$ | Combustion Control | 0.44 lb/hr |
| | VOC | Combustion Control | 0.0007 lb/hp-hr |
| | Greenhouse Gases $CO_2e$ | Combustion Control | 81.2 tpy |
| Cooling Tower | $PM/PM_{10}/PM_{2.5}$ | High efficiency drift eliminators | 0.0005% Drift Eliminator 5.0 tons per year (GE) |
| | | | 0.0005% Drift Eliminator 5.6 tons per year (Siemens) |
| Diesel Tank | VOC | Fixed Roof Tank | $1.4 \times 10^{-4}$ tons per year |

BACT is an emission limitation based on the maximum degree of reduction which the ODEQ determines is achievable, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.

The ODEQ has directed by policy that the BACT be determined using a "top-down" process. The "top-down" process was outlined in a December 1, 1987, memorandum from the EPA Assistant Administrator for Air and Radiation.

While there is no legal requirement to perform the BACT analysis utilizing a specific criteria or process, the ODEQ follows the EPA-developed guidance that establishes a five-step "top-down" BACT process/methodology.[3]

For purposes of its PSD application, WFEC prepared a BACT analysis consistent with EPA's top down approach, which consists of the following steps:

Step 1 – Identify all potential control technologies
Step 2 – Determine technical feasibility (of potential technologies)
Step 3 – Rank control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document results
Step 5 – Select BACT

Each of these steps is discussed in further detail below.

[3] U.S. Environmental Protection Agency. New Source Review Workshop Manual – Draft. North Carolina: Office of Air Quality Planning and Standards, 1990.

**__Step 1 – Identify all potential control technologies__.** The first step in a "top-down" analysis is to identify, for all applicable emission units, all "available" control options. Available control options are defined as those air pollution control technologies or techniques that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation and have been demonstrated in practice. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including innovative fuel combustion techniques and add-on controls.

**__Step 2 – Determine technical feasibility (of potential options)__.** In the second step, the technical feasibility of the control options identified in Step 1 are evaluated with respect to source-specific factors. A demonstration of technical infeasibility should be documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

**__Step 3 – Rank control technologies by control effectiveness__.** All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis.

**__Step 4 – Evaluate most effective controls and document results__.** After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are taken into account, in this step. For each control option an objective evaluation of each impact is presented. Both beneficial and adverse impacts should be discussed and, where possible, quantified. If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding is documented and the next level of control is analyzed.

**__Step 5 – Select BACT__.** The final BACT determination is presented in this step.

**__Greenhouse Gas BACT Process__**

Based on EPA Greenhouse Gas Guidance[4], the Greenhouse BACT process is similar to the five steps summarized above. Steps 1 and 2 identify potential control strategies and then eliminate technologically infeasible options. Step 3 ranks the remaining technically feasible control technologies. Step 4 evaluates the most effective control technologies from an environmental, energy, and economic perspective. And finally, Step 5 selects the most appropriate BACT.

The BACT analysis for the Project is also based on the following concepts:

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[4] PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA, Office of Air Quality Planning and Standards, March 2011.

- Emission limits are defined on a "case-by-case" analysis that considers site specific factors
- Emission limits must be "achievable" on a long-term, day in and day out, basis
- The technology must be available and feasible for a specific project
- BACT does not redefine the facility as proposed (including fuels)

There is no prescriptive approach to performing a case-by-case control technology and emission limit analysis. The ODEQ determines emission limits on a case-by-case basis. These case-by-case determinations must take into account source-specific and site-specific characteristics. This is not a "cookie-cutter" approach and there is no single right answer to determining the appropriate emission limits for a specific source or for a specific pollutant.

The ODEQ is not required to set any emission limit at the most stringent emission limit that has been demonstrated by a facility using similar emissions control technology. Similarly, an emission limit does not need to be set at the most stringent emission limit found in another permit. Rather, the ODEQ has the authority and is required to evaluate and determine the correct emissions limits and control technologies for a particular project based on project-specific factors, including location. The case-by-case process does not require that each subsequent determination identify emission limitations that are equal to or more stringent than the previous determination.

Further, in establishing the emission limits, the BACT must confirm the emission limits are achievable by the specific facility that is subject to the emission limits: (1) over the life of the facility; and (2) during all operating conditions, not just ideal conditions. The use of a safety factor or margin is well-established in the air permitting context to appropriately account for the uncertainty and operational variability that will occur over the life of a facility. This safety factor must be sufficient to allow permit holders to comply on a continuous basis. Emission limits should not be based on the lowest emissions rate or highest control efficiency ever documented by a similar facility for a short-term period. The emission limits must account for a full range of operating conditions and the inherent variability of complex fuel combustion and air pollution control systems.

In order to be considered in the permitting process, a control technology must be commercially available (*i.e.*, it must be offered for sale on a commercial scale through commercial channels). Permittees are not required to explore research and development projects to determine whether or not a particular technology is suitable. In addition, in order to be considered feasible technology for purposes of inclusion in a BACT analysis, a particular technology must have been previously demonstrated, on a long-term basis, at commercial scale. In fact, even 2-3 years of operating history on a commercial scale has been determined to be insufficient to demonstrate that a particular technology is feasible.

The air permit process cannot redefine the source. WFEC has defined the "proposed facility", including the goals, objectives, purpose and basic design. Requiring alteration as to the type of power generating unit and/or range of fuels to be used would redefine the source.

Fuels can be an inherent part of a project design. In such cases, the air permitting process cannot be used to require a fuel other than the fuels proposed by WFEC. As Congress explained, "the Administrator may consider the use of clean fuels to meet BACT requirements <u>if a permit applicant proposes</u> to meet such requirements by using clean fuel. <u>In no case is the</u>

Administrator compelled to require the mandatory use of clean fuels by a permit applicant." (emphasis added). S. Rep. No. 101-228 at 338 (1989).

The first step in the "top-down" BACT process is the identification of potentially available control technologies. One of the ways to identify available control technologies is to review previous BACT determinations for similar sources. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify recent BACT determinations for similar projects. This database is maintained on EPA's Technology Transfer Network website at www.epa.gov/ttn/catc. Advanced queries of the database were conducted to identify control technology determinations from January 2000 to March 2012 for sources similar to the proposed combined cycle combustion turbine and applicable auxiliary equipment. The results of the RBLC query can be found in Appendix D of the application in Tables D-1 to D-6.

To identify previous control technology determinations for comparable sources, a query was run using the "standard search" in which the RBLC database was searched using the following parameters:

- Combustion turbines, Combined-Cycle, 15.210 – Natural gas combustion
- Draft Determinations and RBLC Permits issued during or after January 2000
- Standard Industrial Classification (SIC) code of 4911 for electrical generation plants
- North American Industrial Classification System (NAICS) code for a combustion turbine electrical generation plant 221112 which includes all types of fossil fuel electrical generation plants.
- SIC codes for auxiliary equipment, as applicable

The NAICS and SIC codes are the most appropriate codes to search in the advanced search option of the RBLC. The SIC and NAICS are systems of source classification developed for the purpose of differentiating industrial types. The SIC and the NAICS systems are used in many EPA documents to differentiate types of industries. It is appropriate to use these codes as the match criteria in queries of the RBLC database since other facilities that use similar turbines will likely have similar characteristics. After the NAICS and SIC codes were identified and queries run, combustion turbines that were not similar (e.g., digester gas-fired, fuel oil-fired, cogen units, boilers, simple-cycle combustion turbines etc.) were eliminated from the search. Information on turbine emissions was sorted from the remaining combustion turbine listing. A discussion of control options identified in the RBLC database is included in each subsection. When the combustion turbine results were found in a search, results for the various auxiliary equipment were also available in the search results as well. Therefore, complete RBLC searches were done for all BACT-eligible equipment.

In some cases, the RBLC listings are not clearly categorized and cover both simple- and combined-cycle installations. Also, it should be noted that all RBLC listings in California represent Lowest Achievable Emission Rate (LAER); although they are often listed as BACT, BACT and LAER are essentially the same in California. LAER is a much more stringent requirement than BACT, and involves application of control technology regardless of cost. This is not the case for the proposed Project, which is subject only to BACT.

## 5.1 BACT for Nitrogen Oxides ($NO_x$) – Combustion Turbine

### 5.1.1. Step 1. Identify All Potential Control Strategies

$NO_x$ is primarily formed in combustion processes in two ways:

1. The combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal $NO_x$)

2. The oxidation of nitrogen contained in the fuel (fuel $NO_x$)

Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that essentially all $NO_x$ emissions from the combustion turbine will originate as thermal $NO_x$. The rate of formation of thermal $NO_x$ is a function of residence time and free oxygen and is exponential with peak flame temperature.

The combustion turbine will be subject to $NO_x$ limits per NSPS Subpart KKKK and thus, the BACT determination and resulting emission limits must be at least as stringent as the NSPS. During combined-cycle operation, the duct burners in the HRSGs will contribute to $NO_x$ emissions. The applicable Subpart KKKK limits for the combustion turbine and duct burners is 15 ppmvd @ 15% $O_2$.

Control of $NO_x$ emissions from combustion turbines is generally aimed at either the prevention of $NO_x$ formation or the capture and oxidation of post-combustion $NO_x$. Since the rate of formation of thermal $NO_x$ is a function of residence time and free oxygen, and is exponential with peak flame temperature, "front-end" control techniques are aimed at controlling one or more of these variables. These controls include the XONON™ system and dry low-$NO_x$ burners. The XONON™ system uses a catalyst to keep the system temperatures lower while dry low-$NO_x$ burners offer a staged combustion process, resulting in a lower peak flame temperature.

Other control methods utilize add-on control equipment to remove $NO_x$ from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia into the gas stream to reduce the $NO_x$ to molecular nitrogen and water. Ammonia can either be injected into the system without the use of a catalyst [selective non-catalytic reduction (SNCR)] or with the use of a catalyst (SCR). Finally, SCONO$_x$™ relies upon a catalyst similar to SCR to reduce $NO_x$ emissions, but does so without injecting ammonia into the exhaust gas stream.

The output from the RBLC search provided in Appendix D of the application shows that a variety of emission limits and control technologies have been applied to combustion turbines. The most stringent limits found during a review of EPA's database were for facilities located in ozone non-attainment areas. These facilities were required to meet such low emission limits since they were subject to LAER requirements.

Typical BACT determinations for combined-cycle units that are located in attainment areas were in the 2 to 27 ppm range using dry low-$NO_x$ combustors, water injection, SCR, or a combination of these technologies. The lower emission rates listed utilize SCR.

## 5.11 Step 2. Identify Technically Feasible Control Technologies

### 5.1.1.1 XONON™ System

The XONON™ system controls $NO_x$ emissions by preventing their formation. The key to the XONON™ system is the utilization of a chemical process versus a flame to combust fuel, thus limiting temperature and $NO_x$ formation. The XONON™ system is an integral part of the combustor. The fuel and air that are supplied to the combustor are thoroughly mixed before entering the catalyst. The catalyst is responsible for combusting the fuel to release its energy. Due to the low catalyst operating temperatures, the nitrogen molecules are not involved in the reaction chemistry; they pass through the catalyst unchanged, thereby eliminating $NO_x$ formation. The XONON™ system does have the same high outlet temperature, and some $NO_x$ is formed in the post-combustion process. However, use of the technology has limited $NO_x$ emissions to less than 2.5 ppm.

Currently, the XONON™ system has not had wide-scale application. It has been demonstrated on a 1.5-MW unit in California, with the unit operating in a baseload capacity (24 hours a day, 7 days a week). Tests are underway to apply this technology to other types and sizes of turbines; however, testing data is currently unavailable. As the proposed combustion turbine is expected to experience repeated start-ups and shut downs, it is unclear how the changing load conditions would affect the XONON™ system. As this is a large combined-cycle project, and the XONON™ system has yet to demonstrate applicability for such units, **the XONON™ system has been deemed technically infeasible for this Project.**

### 5.1.1.2 $SCONO_x$™ System

The $SCONO_x$™ system is an add-on control device that reduces emissions of multiple pollutants. The $SCONO_x$™ system utilizes a single catalyst for the conversion of CO, VOC, and $NO_x$ emissions into carbon dioxide ($CO_2$), water, and nitrogen gas. The system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. The $SCONO_x$™ system requires natural gas, water, steam, electricity and ambient air to operate, and no special chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

The exhaust gases of the Project's combined-cycle turbine will be around 200°F. Therefore, the gas stream temperature will be lower than the recommended temperature range for $SCONO_x$™ (300°F to 700°F) so it would need to be heated prior to introduction to the catalyst. Additionally, plant steam would need to be diverted to the catalyst bed in order to regenerate it. The $SCONO_x$™ manufacturer indicated that the technology can be applied to large combined-cycle turbines, **and $SCONO_x$™ is considered to be technically feasible for the Project.**

### 5.1.1.3 Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion $NO_x$ control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with $NO_x$, forming nitrogen and water. The success of this process in reducing $NO_x$ emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700 °F to 2,000 °F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to $NO_x$. Below the lower end of the temperature range, the reagent will not react with the $NO_x$ and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the HRSG have an exhaust temperature of approximately 200°F. Even strategically placing the ammonia injection further upstream would probably result only in peak temperatures of around 1,300°F. Such a low temperature would require that additional fuel be combusted at some point in order to raise the temperature to the levels that SNCR will operate. Combustion of the additional fuel would not only increase the $NO_x$ emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

SNCR has not been applied to any combustion turbines according to the RBLC database. Because of the comparatively low exhaust temperatures, fuel and energy requirements, environmental implications and economic considerations; **SNCR is considered to be technically infeasible for the combustion turbine under consideration for this Project.**

**5.1.1.4 Selective Catalytic Reduction (SCR)**

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert $NO_x$ to nitrogen and water. The function of the catalyst is to lower the activation energy of the $NO_x$ decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art controls for combined-cycle back end gas turbine $NO_x$ removal. SCR technology is being permitted as LAER and BACT for combined-cycle turbines at 2 to 5 ppm $NO_x$. Conventional SCR uses a metal honeycomb or “foil” catalyst support structure and requires an HRSG to drop flue gas temperatures to less than 600°F.

The Project’s turbine will operate with the exhaust gases reaching temperatures over 1,100˚F prior to entering the HRSG. Duct burner firing and passage of the flue gasses through the HRSG will lower the temperature of the gas stream to approximately 200˚F. By placing the catalyst bed at the correct strategic point within the HRSG, an SCR could effectively operate and reduce $NO_x$ emissions. A disadvantage of this system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased particulate matter emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become particulate matter. **SCR can be applied to the combined-cycle turbines and is considered technically feasible.**

**5.1.1.5 Dry Low-$NO_x$ Burners**

Lean premixed combustors are currently available from most turbine manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing $NO_x$. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher $NO_x$ emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers $NO_x$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Controlled $NO_x$ emission guarantees using dry low-$NO_x$ burners range from 9 to 25 ppm for turbines 20 MW or greater, but vary considerably from vendor to vendor. **Low-$NO_x$ burners**

**are currently available for these turbines and duct burners and are a technically feasible control option for this Project.**

**5.1.1.6 Water or Steam Injection**

Steam and water injection works to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel ratio of less than one.

Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent), but there is an increase in power output (typically 5 to 6 percent) due to the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection depending on the amount of water that is injected. Water injection is generally used for fuel oil combustion because it is difficult to aerosolize the fuel oil for air/fuel mixing, or is used on aeroderivative combustion turbines. **Water/steam injection is not currently available for the combined-cycle turbine under consideration for this Project and is therefore considered technically infeasible.**

**5.1.1.7 Summary of the Technically Feasible Control Options**

Technically feasible $NO_x$ control options for the combined-cycle combustion turbine are summarized in Table 5-3. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the combustion turbine. Both combustion turbine options are able to meet the ppm levels in the table with the described controls in each row.

**Table 5-3. Summary of Technically Feasible $NO_x$ Control Technologies for the Combustion Turbine**

| Control System | | Expected Performance (ppm) | Technical Feasibility | Comments |
|---|---|---|---|---|
| Combustion Controls | Dry Low-$NO_x$ Burners | 9 | Feasible | Standard on combustion turbines |
| Post Combusti on Controls | SCONO$_x$™ | 3 | Feasible | Effective over a limited temperature range and would require additional steam resulting in additional emissions |
| | SCR | 2 - 5 | Feasible | 2 ppm is the lowest achievable emission rate with SCR |

**5.1.2 Step 3. Rank the Technically Feasible Control Technologies**

Add-on controls may be used for natural gas combustion in the turbine. The combustion turbines proposed by WFEC come with low $NO_x$ burners as part of their standard packages. The combustion turbine will have low $NO_x$ burners that will control $NO_x$ emissions to 9 ppm for either the GE or the Siemens Option; therefore, low-$NO_x$ burners are used as the baseline for the proposed combustion turbine.

The technically feasible $NO_x$ control technologies for the combustion turbine are ranked by control effectiveness in Table **5-4Table 5-4. Ranking of Technically Feasible $NO_x$ Control Technologies for the Combustion Turbine**

| Control Technology | Reduction (%)[A] | Controlled Emission Level (ppm)[A] |
|---|---|---|
| SCR | 78 – 44 | 2 - 5 |
| SCONO$_x$™ | 67 | 3 |
| Low-$NO_x$ Burners | Not Applicable (baseline) | 9 |

[A] Does not include duct firing. Both combustion turbine options can meet the same ppm with the controls listed.

### 5.1.3 Step 4. Evaluate the Most Effective Controls

Recent BACT determinations have indicated a level of 2 to 25 ppm for $NO_x$ emissions from combined-cycle units that are fired with natural gas see Table D-1, Appendix D of the application. Low-$NO_x$ burners are able to achieve 9 ppm on a long-term basis on the combustion turbines under consideration (not including duct firing).

The Project's combined-cycle unit will have an SCR system located in the HRSG, along with low- $NO_x$ burners which are standard on combustion turbines. The SCR vendors have indicated that 2 ppm is the lowest emission rate achievable with or without the duct burners operating for either combustion turbine option. The SCR system will therefore be able to meet 2 ppmvd for all loads down to 50 percent, including when duct firing. Because SCR represents the most effective control and has been selected as BACT, an economic feasibility determination is not required, per 40 CFR 52.21. The energy and environmental considerations for the selected BACT are discussed below for informational purposes.

SCR is selected as BACT for control of $NO_X$ emissions from the proposed combined-cycle combustion turbine for both the GE Option and the Siemens Option, along with low-$NO_x$ burners.

#### 5.1.3.1 Selective Catalytic Reduction (SCR)

<u>Energy Impacts</u>

An SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas combustion is required to maintain the net energy output, which also results in additional air pollutant emissions.

<u>Environmental Impacts</u>

SCR systems consist of an ammonia injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in a SCR. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip.” It is estimated that ammonia slip from an SCR on a unit this size could be 10 ppm and may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine particulates in the form of ammonium salts. In addition, the storing of the ammonia on-site is another environmental and safety concern. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as a hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in designated landfills.

**5.1.3.2 Low-$NO_x$ Burners**

Energy Impacts

Low $NO_x$ burners are usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). The increase in power output results from the increase in mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Because there is a power increase, no energy impacts are associated with low $NO_x$ burners.

Environmental Impacts

The low $NO_x$ burner system may increase CO and VOC emissions on a lb/hr basis; however, the potential increase in CO and VOC emissions does not outweigh the advantages of decreased $NO_x$ emissions to reduce health effects.

Economic Impacts

The turbine manufacturer currently installs low-$NO_x$ burners as standard equipment on natural gas-fired combustion turbines. With the low-$NO_x$ burners, these turbines may achieve $NO_x$ emission rates of 9 to 12 ppm at full load. Since the low-$NO_x$ burners are considered standard equipment on the turbine, there is no annualized cost of the control.

**5.1.4 Step 5. Selected $NO_x$ BACT Determination**

The BACT selected for control of $NO_x$ emissions from the combined-cycle combustion turbine is low-$NO_x$ burners with SCR and the $NO_x$ emission limits listed below for each combustion turbine option.

**GE Option:**

- 2 ppmvd $NO_x$ at 15 percent oxygen at loads > 50% with and without duct firing
- 23.0 lb/hr $NO_x$ for all loads of 50% and greater

**Siemens Option:**

- 2 ppmvd $NO_x$ at 15 percent oxygen > 50% with and without duct firing
- 23.8 lb/hr $NO_x$ for all loads of 50% and greater

**5.2 BACT for Carbon Monoxide (CO) – Combustion Turbine**

**5.2.1 Step 1. Identify Potential Control Strategies**

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of $NO_x$. Conversely, a lower $NO_x$ emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. A compromise is usually established where the flame temperature reduction is set to achieve the lowest $NO_x$ emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Post-combustion control involves the use of catalytic oxidation; front-end control involves controlling the combustion process to suppress CO formation.

The technologies identified for reducing CO emissions from the Project's turbine are the SCONOx™ system, an oxidation catalyst, and combustion controls. The standard technology for reducing CO emissions is to maintain "good combustion" through proper control and monitoring of the combustion process. A survey of the RBLC database (Table D-2, Appendix D of the application) indicated that most new combined-cycle turbines in attainment areas have been required to install add-on controls to control CO emissions from combined-cycle turbines. CO emissions from natural gas-fired combined-cycle turbines ranged from 1.8 to 40 ppm. It should be noted that the only units that listed BACT at 1.8 ppm are the new G-class combustion turbines which are larger than the F-class combustion turbines proposed for this Project. F-class combustion turbines in combined cycle mode have been permitted from 2 ppm to 9 ppm in most cases, based on the information that is available in the RBLC and from other sources that describe the class of turbines installed at the various locations.

### 5.2.2 Step 2. Identify Technically Feasible Control Technologies

#### 5.2.2.1 SCONO$_x$™ System

The SCONO$_x$™ system was described in the BACT analysis for $NO_x$. It is also applicable for controlling CO and can reduce emissions by up to 90 percent when firing natural gas, depending on the inlet CO emissions. The manufacturer of the SCONO$_x$™ system has indicated that the unit is available for natural gas fired combined-cycle combustion turbines.

**The SCONO$_x$™ system is considered to be technically feasible method of controlling CO emissions from the proposed combined-cycle combustion turbine (both options).**

#### 5.2.2.2 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia with SCR, for a reaction to occur. The oxidation of CO to $CO_2$ utilizes excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities. It is expected that the catalyst would be placed in the exhaust train (HRSG) where the temperature would be optimal for the catalytic reaction.

**The use of an oxidation catalyst is considered to be a technically feasible method of controlling CO emissions from the proposed combined-cycle combustion turbine (both options).**

#### 5.2.2.3 Combustion Control

"Good combustion practices" include operational and incinerator design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion. Such control practices applied to the proposed turbine can achieve CO emission levels of 7 ppm without duct firing and 15 ppm with duct firing at 100 percent load for the GE Option and 4 ppm without duct firing and 12 ppm with duct firing at 100 percent load for the Siemens Option.

**Good combustion practices are considered to be a technically feasible method of controlling CO emissions from the proposed combined-cycle combustion turbine (both options).**

#### 5.2.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the CO control options for the proposed combined-cycle combustion turbine are summarized in Table 5-5. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

**Table 5-5. Summary of Technically Feasible CO Control Technologies for the Combustion Turbine**

| Control System | | Expected Performance (ppm)[A] | Feasibility | Comments |
|---|---|---|---|---|
| Combustion Control | | 3-15 | Feasible | Standard on turbines. Not an add-on control |
| Post Combustion Controls | $SCONO_x$™ | 2 | Feasible | Effective over a limited temperature range and would require additional steam resulting in additional emissions, produces $CO_2$ emissions |
| | Oxidation Catalyst | 2 | Feasible | Produces $CO_2$ emissions |

[A] Does not include duct firing. Emissions expected at 100% load at average ambient conditions for either option.

### 5.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the combustion turbine are ranked by control effectiveness in Table 5-6.

**Table 5-6. Ranking of Technically Feasible CO Control Technologies for Combustion Turbines**

| Control Technology | Reduction (%)[A] | Controlled Emission Level (ppm)[A] |
|---|---|---|
| $SCONO_x$™ | 50-71 | 2 |
| Oxidation Catalyst | 50-71 | 2 |
| Combustion Control | Not applicable (baseline) | 3-15 |

[A] Does not include duct firing. Values at 100% load.

### 5.2.4 Step 4. Evaluate the Most Effective Control Technologies

Operating the proposed combined-cycle combustion turbine with good combustion practices will achieve 8 ppm on a long-term basis (50 percent load and higher without duct firing) and 15 ppm (100 percent load with duct firing) for the GE Option and 9 ppm on a long-term basis (50 percent load and higher without duct firing) and 12 ppm (100 percent load with duct firing) for the Siemens Option. The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

**5.2.4.1 SCONO$_x$™**

The SCONO$_x$™ system uses extra energy to operate because it requires additional modules for the generation of steam in the catalyst bed, which is an additional impact to the energy used for control.

Environmental Impacts

As with any control that uses a catalyst, the spent catalyst must be disposed of in a landfill or hazardous waste facility. Perhaps an even bigger environmental impact of this process is the additional $CO_2$ emissions that will be emitted. The SCONO$_x$™ process converts CO and VOC emissions into $CO_2$ and water. $CO_2$ emissions are being highly scrutinized today due to the perceived effect of greenhouse gasses on the atmosphere. Because $CO_2$ is becoming an undesirable pollutant, the environmental impact of increasing $CO_2$ emissions is considered very high.

Economic Impacts

With the SCONO$_x$™ system, CO is converted into $CO_2$ while VOCs present in the exhaust stream are converted into $CO_2$ and water. The SCONO$_x$™ system requires additional modules to be installed to allow for the generation of steam that will be used in the catalyst bed, and these costs were taken into account. On a per turbine basis, this technology would add a capital cost of approximately $38,880,000 (GE Option) or $44,241,500 (Siemens Option). It would reduce annual CO emissions by 110 tons (GE Option) to 78 tons (Siemens Option). The annualized costs of almost $63,100 per ton of CO removed (GE Option) or even higher cost of $161,800 per ton of CO removed (Siemens Option) are both very expensive and not economically feasible for this project. The capital costs and annual costs are presented in Tables H-1a and H-1b (GE Option) and Tables H-2a and H-2b (Siemens Option) respectively, found in Appendix H of the application.

**With such a large cost of removal per ton of CO removed the SCONO$_x$™ system was rejected as BACT for the combined-cycle combustion turbines (both options).**

**5.2.4.2 Oxidation Catalyst**

Energy Impacts

The addition of a catalyst bed onto the turbine exhaust for the oxidation catalyst will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

Environmental Impacts

The oxidation catalyst oxidizes CO to $CO_2$ which is released to the atmosphere. $CO_2$ is a greenhouse gas that may be contributing to global warming and is now a regulated pollutant. Increasing $CO_2$ emissions could have a negative impact on the atmosphere. However, the oxidation catalyst will also reduce the amount of methane (also a greenhouse gas) and overall considering both greenhouse gases, the net effect is an overall decrease in greenhouse gas emissions on a carbon dioxide equivalent basis.

As with all controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; even if it is not hazardous, it adds to the already full landfills.

Economic Impacts
WFEC has selected the highest control available for CO emissions; therefore no economic analysis is necessary

**The impacts listed above do not outweigh the health benefits of controlling CO emissions with the use of an oxidation catalyst. An oxidation catalyst along with good combustion practices was selected as BACT for the combined-cycle combustion turbine (both options).**

### 5.2.5 Step 5. Selected CO BACT Determination

The BACT selected for control of CO emissions from the proposed combustion turbine is an oxidation catalyst along with good combustion practices. These controls will meet the CO emission limits listed below for each combustion turbine option.

**GE Option:**

- 2 ppm CO at 15 percent oxygen at loads of 50% and higher with and without duct firing
- 14.0 lb/hr CO at 15 percent oxygen for all loads of 50% and greater

**Siemens Option:**

- 2 ppm CO at 15 percent oxygen at loads of 50% and higher with and without duct firing
- 14.5 lb/hr CO at 15 percent oxygen for all loads of 50% and greater

## 5.3 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Combustion Turbine

### 5.3.1 Step 1. Identify Potential Control Strategies

Particulate ($PM/PM_{10}/PM_{2.5}$) emissions from natural gas combustion sources consist of inert contaminants in natural gas, of sulfates from fuel sulfur or mercaptans used as odorants, of dust drawn in from the ambient air, and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions.

A contributor to $PM/PM_{10}/PM_{2.5}$ emissions in combined-cycle turbines with SCR is the ammonium sulfates that are produced when $NO_2$ and ammonia ($NH_3$) react with sulfur in the fuel. The $NO_x$ contained in normal flue gas is generally composed of nitrogen (~95 percent), and $N_2O$ (~5 percent). Sulfur is present in all fuels, including natural gas proposed for this Project. As a result of this sulfur, ammonium sulfates can form, as illustrated by the following equations:

$$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2\ HSO_4$$

$$NH_3 + SO_3 + H_2O \rightarrow NH_4\ HSO_4$$

Ammonium sulfates are also formed when the ammonia content of the flue gas exceeds that of the sulfur ($SO_3$); the amount of ammonium bisulfate then can increase as the ammonia slip increases. Other variables are velocity/temperature profiles, oxygen levels, water content, cycling, presence of a CO catalyst or duct burner, $NH_3/SO_3$ ratios, etc. Therefore, it is expected that combustion turbines with SCR will have higher particulate emissions than those without SCR.

Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas-fired turbines. Available control strategies include the use of low ash fuel, such as natural gas, and combustion controls. BACT emission rates vary in the RBLC database with rates being listed as 0.0035 to 0.066 lb/MMBtu and 0.31 to 45.5 lb/hr. As stated previously, these emission rates vary due to many reasons.

### 5.3.2 Step 2. Identify Technically Feasible Control Technologies

Particulate control devices are not typically installed on gas turbines. Post-combustion controls, such as ESPs or baghouses, have never been applied to commercial gas-fired turbines. Therefore, the use of ESPs and baghouse filters are both considered technically infeasible, and do not represent an available control technology.

In the absence of add-on controls, the most effective control method demonstrated for combustion turbines is the use of low ash fuel, such as natural gas, and combustion controls. This was confirmed by a survey of the RBLC database (see Table D-3, Appendix D in the application) which showed no add-on $PM/PM_{10}/PM_{2.5}$ control technologies for combined-cycle combustion turbine units. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

### 5.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $PM/PM_{10}/PM_{2.5}$ control technologies for the combustion turbines are ranked by control effectiveness in Table 5-7.

**Table 5-7. Ranking of Technically Feasible $PM/PM_{10}/PM_{2.5}$ Control Technologies for Combustion Turbines**

| Combustion Turbine Option | Control Technology | Reduction (%) | Controlled Emission Level (lb/hr) |
|---|---|---|---|
| GE Option | Low Ash Fuel and Combustion Control | Not applicable (baseline) | 22.1 >50% load w/o duct firing<br>31.8 > 50% load with duct firing |
| Siemens Option | | | 22.2 >50% load w/o duct firing<br>31.6 >50% load with duct firing |

### 5.3.4 Step 4. Evaluate the Most Effective Control Technologies

<u>Energy, Environmental, and Economic Impacts</u>

There are no energy, environmental, or economic impacts associated with combustion controls; the use of low ash fuel is not an add-on control device.

### 5.3.5 Step 5. Selected $PM/PM_{10}/PM_{2.5}$ BACT Determination

The use of low ash fuels and good combustion control is selected as BACT for $PM/PM_{10}/PM_{2.5}$ for the proposed combined-cycle combustion turbine and the $PM/PM_{10}/PM_{2.5}$ emissions limits listed below for each combustion turbine option.

**GE Option:**

- 31.8 lb/hr $PM/PM_{10}/PM_{2.5}$ at loads of 50% and higher

**Siemens Option:**

- 31.6 lb/hr $PM/PM_{10}/PM_{2.5}$ at loads of 50% and higher

These limits were converted to 0.0095 lb/mmbtu and compared to information on the RBLC and were found to be equivalent to current emission data.
These limits include front and back half $PM/PM_{10}/PM_{2.5}$ emissions, take into account emissions from the ammonium sulfate produced from sulfur and ammonia slip that could be emitted as $PM/PM_{10}/PM_{2.5}$, and also include the duct burner emissions that will be emitted out of the turbine stack.

**5.4 BACT for Volatile Organic Compounds (VOC) – Combustion Turbine**

**5.4.1 Step 1. Identify Potential Control Strategies**

**5.4.1.1 Formation of VOC and Control Strategies**

Like CO, VOC is a product resulting from incomplete combustion. VOC emissions occur when a portion of the natural gas fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are unreacted trace constituents of the gas, while others may be products of the heavier hydrocarbon constituents. Partially burned hydrocarbons result from poor air-to-fuel mixing prior to, or during, combustion or incorrect air-to-fuel ratios in the combustion turbine.

The technologies identified for reducing VOC emissions from combined-cycle combustion turbines are the same as identified for CO control: the $SCONO_x$™ system, an oxidation catalyst (also referred to as a CO catalyst), and combustion controls. The standard technology for reducing VOC emissions is to maintain "good combustion" through proper control and monitoring of the combustion process through the air-to-fuel ratio. In addition, since most of the BACT determinations for CO for combined-cycle combustion turbines also include an oxidation catalyst, determinations for VOC emissions often include an oxidation catalyst along with good combustion practices. A survey of the RBLC database (see Table D-4, Appendix D in the application) indicates that combustion controls are the most prevalent BACT control along with oxidation catalysts listed as LAER and BACT for VOC. VOC emissions from the permitted facilities ranged from 1 ppm to 7 ppm for natural gas-fired combined-cycle combustion turbines.

**5.4.2 Step 2. Identify Technically Feasible Control Technologies**

**5.4.2.1 $SCONO_x$™ System**

The $SCONO_x$™ system was described in the BACT analysis for $NO_x$ (Section 5.1.2.2). It is also applicable for controlling VOC and can reduce emissions by up to 50 percent. The manufacturer of the $SCONO_x$™ system has indicated that the unit is available for combined-cycle combustion turbines.

**As a result, the $SCONO_x$™ system is considered to be technically feasible for the combined-cycle combustion turbine (both options).**

**5.4.2.2 Oxidation Catalyst**

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia with SCR, for a reaction to occur. The oxidation of CO to $CO_2$ utilizes excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities. It is expected that the catalyst would be placed in the exhaust train (HRSG) where the temperature would be optimal for the catalytic reaction.

The catalyst beds that reduce CO also promote the oxidation of VOC, thereby reducing the VOC emissions out the stack. Such systems typically achieve 20 percent removal of VOC, as opposed to the much higher efficiencies achieved for CO reduction.

**The use of an oxidation catalyst for VOC control is considered to be technically feasible for the combined-cycle combustion turbine (both options).**

#### 5.4.2.3 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion (controlling the air-to-fuel ratio). Such control practices applied to the proposed turbine can achieve VOC emission levels of approximately 5 ppmvd @15% O2 and 17.0 lb/hr for the GE Option and 5 ppmvd @15% O2 and 17.0 lb/hr for the Siemens Option without an oxidation catalyst for loads of 50 percent and higher.

**Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed combined-cycle combustion turbine (both options).**

#### 5.4.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the VOC control options for the proposed combined-cycle combustion turbine are summarized in Table 5-8. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbine.

**Table 5-8. Summary of Technically Feasible VOC Control Technologies for the Combined-Cycle Combustion Turbine**

| Control System | | Expected Performance (lb/hr)* | Feasibility | Comments |
|---|---|---|---|---|
| Combustion Control | | 20.4-21.3 | Feasible | Standard on the proposed combustion turbine. Not an add-on control. |
| Post Combustion Controls | Oxidation Catalyst | 17.0 | Feasible | Produces $CO_2$ emissions. |
| | $SCONO_x$™ | 17.0 | Feasible | Produces $CO_2$ emissions. |

*Emissions expected at 100% load with duct firing at average ambient conditions for either option.

### 5.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the proposed combined-cycle combustion turbine are ranked by control effectiveness in Table 5-9.

**Table 5-9. Ranking of Technically Feasible VOC Control Technologies for the Combustion Turbine**

| Control Technology | Maximum Reduction (%) | Controlled Emission Level (lb/hr)* |
|---|---|---|
| $SCONO_x$™ | 20 | 17.0 |
| Oxidation Catalyst | 20 | 17.0 |
| Combustion Control | Not applicable (baseline) | 20.4-21.3 |

*Emissions expected at 100% load with duct firing at average ambient conditions for either option.

### 5.4.4 Step 4. Evaluate the Most Effective Control Technologies

### 5.4.4.1 Environmental, Energy, and Economic Feasibility of Control Options

The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

#### 5.4.4.1.1 $SCONO_x$™ System

Energy Impacts

The $SCONO_x$™ system uses extra energy to operate because it requires additional modules for the generation of steam that is used on the catalyst bed, which is an additional impact to the energy used for control.

Environmental Impacts

As with any control that uses a catalyst, the spent catalyst must be disposed of in a landfill or hazardous waste facility. Perhaps an even bigger environmental impact of this process is the additional $CO_2$ emissions that will be emitted. The $SCONO_x$™ process converts CO and VOC emissions into $CO_2$ and water. $CO_2$ emissions are being highly scrutinized today due to the perceived effect of greenhouse gasses on the atmosphere. Because $CO_2$ is becoming an undesirable pollutant, the environmental impact of increasing $CO_2$ emissions is considered very high.

Economic Impacts

With the SCONOx™ system, CO is converted into $CO_2$ while VOCs present in the exhaust stream are converted into $CO_2$ and water. The SCONOx™ system requires additional modules to be installed to allow for the generation of steam that will be used in the catalyst bed, and these costs were taken into account. On a per turbine basis, this technology would add a capital cost of approximately $57,191,000 (either Option). It would reduce annual VOC emissions by 42 tons (including duct emissions from duct firing for either option). The annualized costs of over $250,000 per ton of VOC removed (GE Option) or the even higher cost of $251,000 per ton of VOC removed (Siemens Option) are both very expensive and not economically feasible for this project. The capital costs and annual costs are presented in Tables H-5a and H-5b (GE Option) and Tables H-6a and H-6b (Siemens Option), respectively, in Appendix H of the application.

**With such a large cost of removal per ton of VOC removed the SCONOx™ system was rejected as BACT for the combined-cycle combustion turbines (both options).**

#### 5.4.4.1.2 Oxidation Catalyst

Energy Impacts

The addition of a catalyst bed onto the turbine exhaust for the oxidation catalyst will create pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

Environmental Impacts

The oxidation catalyst oxidizes CO and VOC to $CO_2$ which is released to the atmosphere. $CO_2$ is a greenhouse gas that may be contributing to global warming and is now a regulated pollutant. Increasing $CO_2$ emissions could have a negative impact on the atmosphere. However, the oxidation catalyst will also reduce the amount of methane (also a greenhouse gas) and overall considering both greenhouse gasses, the net effect is an overall decrease in greenhouse gas emissions on a carbon dioxide equivalent basis.

As with all controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; even if it is not hazardous, it adds to the already full landfills.

Economic Impacts

WFEC has selected the highest control available for VOC emissions; therefore no economic analysis is necessary.

**Despite such a large cost of removal per ton of pollutant and the added environmental impact of increasing $CO_2$ emissions, an oxidation catalyst was selected as BACT for VOC emissions for the combined-cycle combustion turbines (both options).**

#### 5.4.4.1.3 Combustion Control

There are no energy, environmental or economic concerns with combustion control for VOC emissions.

**Good combustion practices was selected as BACT for VOC emissions along with oxidation catalyst from the proposed combined-cycle combustion turbine (both options).**

### 5.4.5 Step 5. Selected VOC BACT Determination

The BACT recommended for control of VOC emissions from the proposed combustion turbine is the use of an oxidation catalyst and the VOC emission limits listed below for each combustion turbine option.

**GE Option:**

- 5 ppmvd @15% O2 with and without duct firing
- 17.0 lb/hr VOC for loads of 50% and greater

**Siemens Option:**

- 5 ppmvd @15% O2 with and without duct firing
- 17.0 lb/hr VOC for loads of 50% and greater

## 5.5 BACT for Greenhouse Gases (GHG) – Combustion Turbine

### 5.5.1 Step 1. Identify All Potential Control Strategies

For the proposed combined-cycle combustion turbine, the $CO_2e$ emissions are due to $CO_2$, $CH_4$, and $N_2O$ emissions. GWP of $CH_4$ and $N_2O$ emissions are normalized to the warming potential of carbon dioxide (as $CO_2e$) by multiplying the $CH_4$ emissions by 21 and the $N_2O$ emissions by 310. Despite the higher warming potentials of $CH_4$ and $N_2O$ compared to $CO_2$, it is expected that $CO_2$ emissions will still account for over 99 percent of the $CO_2e$ for this unit, based on published emission factors for natural gas-fired turbines.

There are two broad strategies for reducing $CO_2$ emissions from stationary combustion processes such as combustion turbines. The first is to minimize the production of $CO_2$ through the use of low-carbon fuels and through aggressive energy-efficient design. The use of gaseous fuels, such as natural gas, reduces the production of $CO_2$ during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils). Additionally, a highly efficient operation requires less fuel for process heat, which directly impacts the amount of $CO_2$ produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce $CO_2$ production and the costs to recover it.

The second strategy for $CO_2$ emission reduction is carbon capture and sequestration (CCS). The inherent design of the combustion turbines produces a dilute $CO_2$ stream for potential capture.

The $CO_2$ emissions from combustion turbines can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated $CO_2$ exhaust gas is generated. This approach significantly reduces the capital and energy cost of removing $CO_2$ from conventional combustion processes using air as an oxygen source, but it incurs significant capital and energy costs associated with separating oxygen from the air.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate $CO_2$ from the combustion exhaust gases. Because the air used for combustion contains nearly 80 percent nitrogen, the $CO_2$ concentration in the exhaust gases is only 5 to 20 percent depending on the amount of excess air and the carbon content of the fuel.

#### 5.5.1.1 Proposed New Source Performance Standard for New Power Plants

In April 2012, the EPA proposed Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units (NSPS Subpart TTTT). The proposed rule would apply only to new fossil-fuel-fired electric utility generating units (EGUs). Fossil-fuel-fired EGUs include fossil-fuel-fired boilers, integrated gasification combined cycle units and stationary combined-cycle turbine units that generate electricity for sale and are larger than 25 MW. This rule applies to coal, biomass, natural gas and fuel oil units. The proposed limit for $CO_2$ is 1,000 lb/MW-hr for all of these units. Although this rule is only proposed at this time, this BACT analysis will consider the NSPS proposed limit as a “not-to-exceed” value.

### 5.5.2 Step 2. Identify Technically Feasible Control Technologies

#### 5.5.2.1 Fuel Selection

##### 5.5.2.1.1 Low-Carbon Fuels

Numerous fuels are available for use. As Table 5-10 shows, combustion of natural gas yields 40 to 50 percent less $CO_2$ than does combustion of coal and petroleum coke and approximately 30 percent less $CO_2$ than does combustion of residual oil. Accordingly, the preferential burning of a low-carbon gaseous fuel in the proposed combustion turbine is an extremely effective $CO_2$ control technique. This control technique is **technically feasible** for the combustion turbine and duct burner and is an inherent part of the Project's design.

**Table 5-10. $CO_2$ Emission Factors**

| Fuel | Pounds $CO_2$ per Million Btu[A] |
|---|---|
| Petroleum Coke | 225 |
| Coal | 210 |
| Residual Oil | 174 |
| Natural Gas | 117 |

[A] Energy Information Administration at http://www.eia.doe.gov/oiaf/1605/coefficients.html

#### 5.5.2.1.2 Combustion of Biogenic Sources

On July 1, 2011, EPA signed a 3-year deferral on counting $CO_2$ emissions from biogenic sources towards PSD and Title V applicability. In addition, the proposed combustion turbine has not been designed to accommodate fibrous biomass, such as woody biomass, which is the most likely biomass available in sufficient quantities for the unit from the surrounding area. For both regulatory and technical feasibility issues, therefore, **biogenic sources are not a feasible option**.

### 5.5.2.2 Energy Efficiency

#### 5.5.2.2.1 Continuous Excess Air Monitoring and Control

Excessive amounts of combustion air in turbines results in energy-inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only $CO_2$ emissions but also $NO_x$ emissions. The combustion turbine will be equipped with oxygen monitors as part of the CEM system.

#### 5.5.2.2.2 Selection of Efficient Turbine Design

This option reduces $CO_2$ emissions by ensuring that the combustion turbine is as efficient as possible, thereby reducing the amount of fuel burned per megawatt-hr produced.

- Combustion control optimization and energy efficient equipment – The combustion turbine design for both turbines that are under consideration are both highly efficient. This is technically and economically feasible. Potential options that may increase efficiency include the following for each combustion turbine option:

  **GE Option:**

  - Airfoil-shaped compressor rotor blades designed to increase compressor efficiency

- 14 stage high efficiency compressor design with modulating inlet guide vanes and interstage air extraction for cooling and sealing air
- Fuel gas heating via HRSG feedwater to improve turbine efficiency while maintaining constant firing temperature
- Inlet air filtration system utilizing high efficiency media filters to remove combustion air contaminants
- On and off-line compressor water wash capability to remove deposits and other contaminants from compressor blades to maintain and improve compressor efficiency
- Industry-leading dry-low $NO_x$ 2.6 combustor for improved performance, enhanced operability, and lower emissions
- Extended turndown for increased spinning reserve capability and lower fuel costs
- Advanced hot gas path components with 3D airfoil shapes, improved materials, improved sealing, more effective cooling to achieve increased turbine efficiency
- Higher firing temperatures to increase turbine performance and overall turbine efficiency

**Siemens Option:**

- Latest burner technology in fleet operation leading to ultra-low $NO_x$ and $CO_2$ emissions
- Fast ramp-up/ramp-down
- High turn-down capability (single-digit emissions between 40 and 100 percent base load)
- High starting reliability
- 13-stage high-efficiency, axial flow compressor with variable inlet guide vanes
- Fuel gas heating via HRSG feedwater to improve turbine efficiency
- Inlet air filtration utilizing high efficiency cartridge filters to clean combustion air and remove contaminants
- On and off-line compressor water wash system to remove deposits and other contaminants from compressor blades to maintain efficient operation

- Flue gas heat recovery- Combustion air is preheated using a flue gas heat recovery system.
- Steam turbine design –The proposed steam turbine will incorporate a high efficiency design. This is technically and economically feasible.
- Combined heat and power plant –There are no nearby industries which could use process steam from the combustion turbine, so this is not technically feasible.

**5.5.2.3 Add-on Control Devices**

**5.5.2.3.1 Catalytic Oxidation**

$N_2O$ emissions are reduced by passing the combustion gases over a catalyst, converting the same to nitrogen plus oxygen. Similarly, VOC emissions, such as $CH_4$, may be converted from $CH_4$ to $CO_2$ plus water. For the same reasons given above in the discussion for CO BACT controls, **catalytic oxidation is technically feasible for the control of GHG emissions from the proposed combined cycle combustion turbine (both options).**

#### 5.5.2.3.2 Thermal Oxidation

There are several types of thermal oxidation technology. All of these technologies oxidize $CH_4$ to $CO_2$ and water, by raising the temperature of the gas stream being treated to approximately 1,600ºF for approximately one to two seconds. Given sufficient mixing, this residence time and temperature is capable of achieving at least a 98 percent reduction in $CH_4$ emissions for these processes. Secondary pollutants are produced by thermal oxidation. These include $NO_x$ and CO from the combustion of natural gas used to heat the process stream. Thermal oxidation technologies also may employ some form of heat recovery, either recuperative or regenerative, to reduce economic, environmental and energy costs. In the case of a combustion turbine, it is expected that approximately 20 lb/hr of $CH_4$ will be produced at full load (with an exhaust flow rate of approximately 1,000,000 million standard cubic feet per minute). The exhaust gas stream is thus both high volume and very dilute in $CH_4$, so it would need to be concentrated to the point that the $CH_4$ would be capable of combustion. Also, additional $CO_2$ would be produced due to the need for combusting natural gas to heat the $CH_4$ to the oxidation point. This would reduce the overall effectiveness in reducing $CO_2$e emissions due to $CH_4$ because additional $CO_2$ would be produced as a result of combusting the $CH_4$. **Therefore, thermal oxidation is technically infeasible for the control of GHG emissions from the proposed combined-cycle combustion turbine.**

### 5.5.2.4 Carbon Dioxide Capture and Sequestration (CCS)

This is a general term which is used for approaches that capture and separate $CO_2$ from an exhaust stream, and then store it in a place which will keep it from the atmosphere for a long time. The two general categories of $CO_2$ capture are: pre-combustion $CO_2$ capture and post-combustion $CO_2$ capture.

#### 5.5.2.4.1 Pre-combustion $CO_2$ Capture

Pre-combustion $CO_2$ capture is used in gasification plants, where the $CO_2$ is captured from the syngas prior to combustion in the turbine, where it is relatively concentrated in the gas stream. This facility is not a gasification plant; therefore **pre-combustion capture is technically infeasible for the control of $CO_2$ emissions from the proposed combined-cycle combustion turbine**.

#### 5.5.2.4.2 Post-combustion $CO_2$ Capture

Post-combustion $CO_2$ capture is used for units such as pulverized coal plants. In these units, the flue gas concentration of $CO_2$ runs between 10-15 percent by volume, and is released at atmospheric pressure. This results in a high actual volume of gas to be treated, while trace impurities in the airflow tend to reduce the effectiveness of the $CO_2$ adsorbing process, and compressing the captured $CO_2$ from atmospheric pressure to pipeline pressure represents a large parasitic load. The currently available process is costly and energy intensive, so research is being done on ways to increase the solvent capture efficiency and reduce the cost. These approaches include investigating the use of alternative solvents, solid sorbents or membranes. Of these potentially more efficient approaches, most are currently at laboratory/bench scale, so are not technically feasible. Pilot scale processes are starting to be placed in service, such as a 48 MW slipstream project at Brindisi, Italy, started in March 2011, which is limited to capturing less than 10,000 tons of $CO_2$ per year. A larger 235-MW slipstream project for the 1,300 MW Mountaineer Power Plant near New Haven, West Virginia was scheduled to begin operation in 2016. No commercially available post-combustion $CO_2$ capture systems are known to have been installed at large power plant other than pilot-scale demonstration projects. Therefore, **post-**

**combustion capture is technically infeasible for the control of $CO_2$ emissions from the proposed combined-cycle combustion turbine**.

### 5.5.2.4.3 $CO_2$ Sequestration

$CO_2$ sequestration involves transporting $CO_2$ to a suitable geologic location where it can be injected as a supercritical fluid into deep, underground rock formations for permanent storage. Identifying a suitable site within an economically-viable distance will require site-specific quantitative risk assessment. Four trapping methods are known: mineral trapping, physical adsorption, hydrodynamic trapping, and solubility trapping.

#### 5.5.2.4.3.1 Mineral Trapping

In this method, the $CO_2$ is trapped by undergoing a chemical reaction with various minerals, resulting in the formation of a carbonate mineral. This process can be rapid or very slow, depending on the chemistry of the rock and water at the site. Mineral trapping is expected to result in the most stable, permanent form of geological $CO_2$ sequestration. Experiments have shown that basalt formations can rapidly transform injected $CO_2$ into carbonate minerals, beginning precipitation in a few months' time and completing conversion within 100 years or less, depending on depth of injection. Sandstone formations low in carbonates may also be suitable candidates, depending on the mineral contents of the formations. These methods have been demonstrated only on a laboratory scale, so are **not technically feasible for the proposed combined-cycle combustion turbine**.

#### 5.5.2.4.3.2 Physical Adsorption

In this case, $CO_2$ molecules are trapped in micropore wall surfaces of coal organic matter or organic rich shales. The hydrostatic pressure in the formation controls the adsorption process. The injection of $CO_2$ can also result in driving off $CH_4$ for collection by other wells, helping the economics. Oklahoma has coal beds in the mid-northeast part of the state (Northeast Oklahoma Shelf and Arkoma Basin). There is a commercial coal belt that contains coal beds greater than or equal to 10 inches thick. The coal beds that are greater than or equal to 14 inches thick are mineable by underground methods. Coal mining in Oklahoma has been steadily decreasing since 1981. Some coal beds in the US are being tested for $CO_2$ storage/ $CH_4$ recovery, but this is currently at a pilot phase. Defining the depths and lateral distribution of coal strata that might be suitable for this approach has not been done, due to the significant depths required for $CO_2$ sequestration. Significant research and exploration efforts would be required to determine whether or not such coal beds even actually occur at the required depths beneath western Oklahoma. Use of coal beds in Oklahoma would require much further study to locate a suitable site for sequestration, and since the results of pilot phase testing of this technique are not known, these factors combine to render the use of coal beds currently **not technically feasible for the proposed combined-cycle combustion turbine.**

#### 5.5.2.4.3.3 Hydrodynamic Trapping

In this case, the pore space of a salt-water aquifer takes the injected $CO_2$, in a geologic setting where the aquifer is capped by an impermeable rock layer to trap the $CO_2$ well below the near-surface environment. For storage purposes, the aquifer should be saline enough to be non-potable, and deep enough (over 2,700 feet) to ensure that the pressure is sufficient to keep the compressed $CO_2$ in a supercritical liquid phase. Since the sedimentary bedrock strata in the site vicinity are over 10,000 feet thick, the possibility exists that geologically suitable strata exist somewhere within these layered rock formations. However, in the absence of oil and gas exploratory test holes, the locations, depths, and character of such strata are not known, and would have to be discovered and defined by extensive exploratory drilling and testing. As the state of Oklahoma is unlikely to apply for primacy for the Class VI regulations (governing injection wells), EPA rules that require a minimum of 10,000 milligrams per liter (mg/L) TDS to qualify as saline enough to be suitable for injection will probably apply. Discovering locations which exceed 10,000 milligrams per liter would require significant exploration and test wells to characterize the site and determine the aquifer suitability. At these depths, defining suitable geologic would be rendered costly and problematic. Multiple oil and gas fields exist in the region, but a serious limitation to feasibility in an existing oil or gas field is the great likelihood of significant numbers of "penetrations" (old, either documented or undocumented wells and test holes that may or may not be adequately plugged & abandoned. Also, the additional surface infrastructure that would be needed to inject $CO_2$ would be massive, problematic, and likely infeasible. Pilot-scale projects injecting $CO_2$ into saline aquifers are underway in Illinois and Texas at depths of over 6,000 feet and these are the closest known sites that have been initially characterized for potential long term sequestration, but the studies are in their early stages. Therefore, hydrodynamic trapping is **technically infeasible for the control of $CO_2$ emissions from the proposed combined-cycle combustion turbine** at this time.

**5.5.2.4.3.4 Solubility Trapping**

In this case, the $CO_2$ dissolves in the water or forms carbonic acid, becoming slightly heavier and, theoretically, sinking to the bottom of the aquifer. Solubility trapping also occurs during $CO_2$ flooding for enhanced oil recovery (EOR). In this case, the $CO_2$ dissolves into the oil, and is trapped by the immobile, non-recoverable oil. $CO_2$ flooding has been used for years for EOR, resulting in some existing injection infrastructure at oil fields (actually using both solubility trapping and hydrodynamic trapping), although the sequestration effects were not originally monitored, and the volumes injected for such operations are minuscule. However, oil fields have stored crude oil and natural gas for millions of years, and the geologic conditions that trap oil and gas are also the conditions suitable for $CO_2$ storage. If the $CO_2$ is used for EOR, the cost of transporting it to the oil field may be partially offset. Since the sedimentary bedrock strata in the site vicinity are over 10,000 feet thick, the possibility exists that oil and gas fields involving geologically suitable strata exist somewhere within these layered rock formations within the region. However, defining suitable geologic conditions in an existing oil or gas field, including the locations, depths, and character of such strata would have to be defined by extensive exploratory drilling and testing. Multiple oil and gas fields exist in the region, but a serious limitation to feasibility in an existing oil or gas field is the great likelihood of significant numbers of "penetrations" (old, either documented or undocumented wells and test holes that may or may not be adequately plugged and abandoned). Also, additional surface infrastructure that would be needed to inject $CO_2$ would be massive, problematic, and likely infeasible. Therefore, solubility trapping is **technically infeasible for the control of $CO_2$ emissions from the proposed combined-cycle combustion turbine** at this time.

**5.5.2.4.4 Summary of $CO_2$ Sequestration**

To summarize, existing $CO_2$ capture technologies have not been applied at large power plants, as the economic costs are prohibitive, and while more efficient approaches are being investigated, none have currently been developed past the pilot-stage. A published cost estimate for a 235-MW slipstream pilot project in West Virginia is $668 million, so scaling that linearly to a size capable of handling the approximate 300–net-MW capacity of this project would be over $1.7 billion. Potential carbon sequestration sites may exist in Oklahoma, but the technologies to use them are mostly still in the pilot-scale phase of development, and WFEC would need to do much more investigation in order to discover where the sites are, if any, and characterize them enough to demonstrate the long-term viability of the locations. Defining suitable geologic conditions in an existing oil or gas field, including the locations, depths, and character of suitable strata, and defining penetrations (potentially leaky wells and test holes, some of which are likely to exist but are undocumented) into the geological traps comprising existing oil and gas fields, would have to be defined by extensive exploratory drilling and testing. One of the closest known existing sites for sequestration is the Willston Basin in the Dakotas, approximately 1,000 miles from the plant. The cost to construct a pipeline as determined from a similar project (Iowa Power &Light Ottumwa – Iowa Department of Natural Resources project 11-219) to this project's site would be approximately $1.4 million/mile of pipeline, or about $700 million. The capital cost estimated for this comparable project was nearly $2.1 billion for capture equipment and pipeline construction alone prior to any costs for gas compression, additional injection and monitoring wells necessary to handle the volume of $CO_2$ produced, pipeline right-of-way, operation and maintenance costs, etc. The facts are that the qualitative cost estimate of capture and sequestration is quite high, the technological effectiveness for the capture equipment for a unit of this size has not been demonstrated in practice yet, and there is uncertainty as to whether locations capable of storing the large amounts of $CO_2$ that would be produced per year exist within a closer radius of the plant, are sufficient to eliminate this option without requiring a more detailed site-specific technological or economic analysis.

**5.5.2.4.5 Summary of Technically Feasible Control Technologies**

The technical feasibility of the greenhouse gas control options for the proposed combustion turbine (both options) is summarized in Table 5-11. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbine.

**Table 5-11. Summary of Technically Feasible Greenhouse Gas Control Technologies for Combustion Turbine**

| Control System | | Technical Feasibility | Comments |
|---|---|---|---|
| Fuel Selection | Low Carbon Fuels | Feasible | Natural gas has been selected as the fuel for this project |
| | Combustion of Biogenic Sources | Not Feasible | -- |
| Energy Efficiency | Continuous Excess Air Monitoring and Control | Feasible | Standard for the turbines under consideration |
| | Efficient Turbine Design | Feasible | Standard for the turbines under consideration |
| Post Combustion Controls | Catalytic Oxidation | Feasible | Will reduce $CH_4$ emissions but create $CO_2$ |
| | Thermal Oxidation | Not Feasible | -- |

| | | | |
|---|---|---|---|
| Carbon Capture | Pre-combustion $CO_2$ capture | Not Feasible | -- |
| | Post-combustion $CO_2$ capture | Not Feasible | -- |
| Carbon Sequestration | Mineral Trapping | Not Feasible | -- |
| | Physical Adsorption | Not Feasible | -- |
| | Hydrodynamic Trapping | Not Feasible | -- |
| | Solubility Trapping | Not Feasible | -- |

### 5.5.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible control technologies are low-carbon fuel (natural gas), monitoring and control of excess air, efficient turbine design, and catalytic oxidation. The use of low-carbon fuels and aggressive energy-efficient design to reduce $CO_2$ emissions is inherent in the design of the proposed combustion turbine under consideration and is considered the baseline condition.

Table 5-12 presents the ranking of the greenhouse gas technologies determined to be feasible for the Project. The technologies are "ranked" in order of their presentation.

**Table 5-12. Greenhouse Gas Control Technology Ranking for the Combustion Turbine**

| Technology | Ranking | Applied to Project |
|---|---|---|
| Combined – Cycle Combustion Turbine (employing efficient, state-of-the-art design) | 1 | Yes |
| Clean Fuel – Natural Gas | 2 | Yes |
| Operational Design – Control of Excess Air | 3 | Yes |

### 5.5.4 Step 4. Evaluate the Most Effective Control Technologies

#### 5.5.4.1 Environmental, Energy, and Economic Feasibility of Control Options

Because WFEC is proposing to utilize three of the four feasible technologies for reducing greenhouse gases from the proposed combustion turbine, no detailed analysis is provided to compare the available control technologies' relative environmental, energy and economic impacts.

### 5.5.5 Step 5. Selected Greenhouse Gas BACT Determination

BACT for greenhouse gas emissions associated with the proposed combined-cycle combustion turbine is determined to be the use of natural gas as a fuel, monitoring and control of excess air, and efficient turbine design, at a rate not to exceed 1,000 lb $CO_2$/gross MW-hr on an annual average basis.

## 5.6 BACT for Start-Up and Shut Down Emissions – Combustion Turbine

### 5.6.1 Step 1. Identify Potential Control Strategies

Criteria pollutants will be emitted during start-up and shut down of the combustion turbine. Start-up emissions are generally higher for CO, $NO_x$, and VOC than for normal operation because the SCR and oxidation catalyst cannot fully operate to their full potentials until the exhaust gases reach the appropriate operating temperature.

WFEC proposed a limit of 365 start-ups and 365 shut downs per year for the combined-cycle combustion turbine (for either combustion turbine option). Start-up is defined as 0 to 50 percent load and shut down is defined as 50 to 0 percent load.

### 5.6.2 Step 2. Identify Technically Feasible Control Technologies

Controls that may be used during normal operation are not available to control start-up and shut down emissions. SCR and oxidation catalysts require a minimum operating temperature to control emissions (for the catalytic reactions to occur for removal of $NO_x$ and CO). This temperature is not reached until approximately 600 to 650 °F. Although this temperature is reached in the HRSG before 50 percent load, the CO and $NO_x$ curves show that these emissions are unstable until around 50 percent load. (See the startup curve in Appendix C of the application.) In addition, the manufacturer will only guarantee emissions down to 50 percent load, indicating that this is where stability in these emissions is reached. To minimize emissions, however, start-up and shut down shall be limited to 4 hours per start-up and 1 hour per shutdown. No technically feasible control technologies for start-up and shut down emissions from the combustion turbine were identified.

### 5.6.3 Step 3. Rank the Technically Feasible Control Technologies

Since no technically feasible control technologies for start-up and shut down emissions were identified, ranking of such control technologies is not applicable.

### 5.6.4 Step 4. Evaluate the Most Effective Control Technologies

Energy, Environmental, and Economic Impacts

Since no technically feasible control options for start-up and shutdown emissions were identified, evaluation of environmental, energy or economic impacts of such control technologies is not applicable.

### 5.6.5 Step 5. Selected Start-up and Shutdown BACT Determination

BACT is selected as limiting start-ups to 365 per year and limiting shutdowns to 365 per year, and limiting startup times to 4 hours per occurrence and shutdown times to 1 hour per occurrence.

Table 5-13 displays the BACT emission rates for start-up and shut down emissions for the GE Option combustion turbine.

Table 5-14 displays the BACT emission rates for start-up and shut down emissions for the Siemens Option combustion turbine.

**Table 5-13. GE Option - Combustion Turbine Start-up and Shut down Emissions**

| Pollutant | Number of Start-ups and Shut Downs per Year[A] | lb/Start-up | lb/Shut Down | Total Start-up and Shut Down Emissions (Tons per Year) |
|---|---|---|---|---|
| $NO_x$ | 365 | 573.2 | 48.3 | 113.4 |
| CO | 365 | 1,363.4 | 151.1 | 281.3 |
| $PM/PM_{10}/PM_{2.5}$ | 365 | 66.9 | 6.6 | 13.4 |
| VOC | 365 | 162.8 | 23.5 | 34.0 |
| $CO_2e$ | 365 | 1,176,743.6 | 116,701.8 | 236,054 |

[A] 365 start-ups and 365 shut downs per year.

**Table 5-14. Siemens Option - Combustion Turbine Start-up and Shut down Emissions**

| Pollutant | Number of Start-ups and Shut Downs per Year[A] | lb/Start-up | lb/Shut Down | Total Start-up and Shut Down Emissions (Tons per Year) |
|---|---|---|---|---|
| $NO_x$ | 365 | 573.2 | 48.3 | 113.4 |
| CO | 365 | 1363.4 | 151.1 | 281.3 |
| $PM/PM_{10}/PM_{2.5}$ | 365 | 67.1 | 6.7 | 13.5 |
| VOC | 365 | 162.8 | 23.5 | 34.0 |
| $CO_2e$ | 365 | 1,223,427 | 121,332 | 245,419 |

[A] 365 start-ups and 365 shut downs per year.

### 5.7 <u>BACT Analysis for Emergency Diesel Generator</u>

One 1,000 kW (1,341 hp) emergency diesel generator will be installed for the Project. The emergency diesel generator will be limited to 100 hours per year (for testing and maintenance purposes) and will utilize ultra-low sulfur transportation grade distillate fuel oil, with a sulfur content of no more than 0.0015 weight percent. The emergency diesel generator will comply with the applicable NSPS requirements. The RBLC has limited information on BACT conclusions for small engines such as the emergency diesel generator (see Table D-5, Appendix D of the application). The RBLC tables also show high variability for emission rates for each pollutant. For all pollutants, no add-on controls were listed because the same were determined to not be economically feasible due to engine size.

#### 5.7.1 BACT for Nitrogen Oxides ($NO_x$) – Emergency Diesel Generator

#### 5.7.1.1 Step 1. Identify Potential Control Strategies

For an emergency diesel generator that only operates 100 hours per year for testing and maintenance, there are no controls that are available that would even be close to being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul an SCR catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an SCR system may be technically feasible.

**5.7.1.2 Step 2. Identify Technically Feasible Control Technologies**
**5.7.1.2.1 SCR**
The RBLC did not list any add-on control devices as BACT for the emergency diesel generator; however, an SCR may be available for this size of engine.

**As a result, an SCR system is considered technically feasible for the emergency diesel generator.**

**5.7.1.2.2 Combustion Control**
"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**As a result, combustion control is considered baseline for the emergency diesel generator and is technically feasible.**

**5.7.1.3 Step 3. Rank the Technically Feasible Control Technologies**
The technically feasible $NO_x$ control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-15.

**Table 5-15. Ranking of $NO_x$ Control Technologies for the Emergency Diesel Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hp-hr)] |
|---|---|---|
| SCR | 90 | 0.0011 |
| Combustion Control | Not applicable (baseline) | 0.011 |

**5.7.1.4 Step 4. Evaluate the Most Effective Control Technologies**
Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

**5.7.1.4.1 SCR**
<u>Energy and Environmental Impacts</u>
Energy and environmental impacts for an SCR system are discussed in Section 5.1.2.4.
<u>Economic Impacts</u>
Because this unit will only operate 100 hours per year for testing and maintenance, a cost analysis is not needed to show that the cost per ton of $NO_x$ removed would be economically infeasible. The emergency diesel generator will only emit 0.71 tons per year of $NO_x$, based on the annual 100-operating-hour limitation. An SCR system would cost much more than $10,000 per ton of $NO_x$ removed.
**Therefore, an SCR is not considered as BACT because it is not economically feasible for the emergency diesel generator.**

**5.7.1.4.2 Combustion Control**
**Energy, Environmental, and Economic Impacts**
Combustion control is accomplished through operational control of the engines; therefore, there are no energy, environmental, or economic impacts associated with this control.

**5.7.1.5 Step 5. Selected $NO_x$ Emergency Diesel Generator BACT Determination**
Combustion control was determined as BACT for $NO_x$ for the emergency diesel generator; add-on controls are not practical on a unit this size, with limited operation, and the economic impacts are high. The emergency diesel generator will be able to achieve 0.011 lb/hp-hr of $NO_x$ emissions on an on-going basis.

**5.7.2 BACT for Carbon Monoxide (CO) – Emergency Diesel Generator**
**5.7.2.1 Step 1. Identify Potential Control Strategies**
For an engine that only operates 100 hours per year for testing and maintenance, there are no controls that are available that would even be close to being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul the oxidation catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an oxidation catalyst may be technically feasible.

**5.7.2.2 Step 2. Identify Technically Feasible Control Technologies**
**5.7.2.2.1 Oxidation Catalyst**
The RBLC did not list any add-on control devices as BACT for the emergency diesel generator; however, an oxidation catalyst may be available for this small engine size.

**As a result, an oxidation catalyst system is considered technically feasible for the emergency diesel generator.**

**5.7.2.2.2 Combustion Control**
"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**As a result, combustion control is considered baseline for the emergency diesel generator and is technically feasible.**

**5.7.2.3 Step 3. Rank the Technically Feasible Control Technologies**
The technically feasible CO control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-16.

**Table 5-16. Ranking of CO Control Technologies for the Emergency Diesel Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hp-hr) |
|---|---|---|
| Oxidation Catalyst | 90 | 0.00001 |
| Combustion Control | Not applicable (baseline) | 0.001 |

#### 5.7.2.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

#### 5.7.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts for an oxidation catalyst are discussed in Section 5.2.2.2.

Economic Impacts

Because the emergency diesel generator only operates for 100 hours per year for testing and maintenance, a cost analysis is not needed to show that the cost per ton of CO removed would be economically infeasible. The emergency diesel generator will only emit 0.37 tons per year of CO, based on the annual 100 operating hour limitation. An oxidation catalyst system would cost much more than $10,000 per ton of CO removed.

**Therefore, an oxidation catalyst is not proposed as BACT because it is not economically feasible for the emergency diesel generator.**

#### 5.7.2.4.2 Combustion Control

**Energy, Environmental, and Economic Impacts**

Combustion control is accomplished through operational control of the engine, therefore, there are no energy, environmental, or economic impacts associated with this control.

#### 5.7.2.5 Step 5. Selected CO Emergency Diesel Generator BACT Determination

Combustion control was selected as BACT for CO for the emergency diesel generator; add-on controls are not practical on this small unit with limited operation and economic impacts are high. The emergency diesel generator will be able to achieve 0.001 lb/hp-hr of CO emissions on an on-going basis.

### 5.7.3 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Emergency Diesel Generator

#### 5.7.3.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (fuel oil) for the emergency diesel generator. No add-on controls were identified for significant removal of these pollutants from the engine’s exhaust.

#### 5.7.3.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for $PM/PM_{10}/PM_{2.5}$.

#### 5.7.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $PM/PM_{10}/PM_{2.5}$ control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-17.

**Table 5-17. Ranking of $PM/PM_{10}/PM_{2.5}$ Control Technologies for the Emergency Diesel Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hr) |
|---|---|---|

| | | |
|---|---|---|
| Combustion Control | Not applicable (baseline) | 0.44 |

#### 5.7.3.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for $PM/PM_{10}/PM_{2.5}$

Since no add-on controls were identified, combustion control with low ash fuel was selected as BACT for $PM/PM_{10}/PM_{2.5}$ at an emission rate of 0.44 lb/hr for the emergency diesel generator.

### 5.7.4 BACT for Volatile Organic Compounds (VOC) – Emergency Diesel Generator

#### 5.7.4.1 Step 1. Identify Potential Control Strategies

For an engine that only operates 100 hours per year for testing and maintenance, there are no controls that are available that would even be close to being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul the oxidation catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an oxidation catalyst may be technically feasible.

#### 5.7.4.2 Step 2. Identify Technically Feasible Control Technologies

##### 5.7.4.2.1 Oxidation Catalyst

Although the RBLC did not list any add-on control devices as BACT for the emergency diesel generator, an oxidation catalyst may be available for this small engine.

**As a result, an oxidation catalyst system is considered technically feasible for the emergency diesel generator.**

##### 5.7.4.2.2 Combustion Control

“Good combustion practices” include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**As a result, combustion control is considered baseline for the emergency diesel generator and is technically feasible.**

#### 5.7.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-18.

**Table 5-18. Ranking of VOC Control Technologies for the Emergency Diesel Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hp-hr) |
|---|---|---|
| Oxidation Catalyst | 25 | 0.0005 |
| Combustion Control | Not applicable (baseline) | 0.0007 |

**5.7.4.4 Step 4. Evaluate the Most Effective Control Technologies**
Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

**5.7.4.4.1 Oxidation Catalyst**
<u>Energy and Environmental Impacts</u>
Energy and environmental impacts for an oxidation catalyst are discussed in Section 5.2.2.2.

<u>Economic Impacts</u>
Because the emergency diesel generator will only operate 100 hours per year for testing and maintenance, a cost analysis is not needed to show that the cost per ton of VOC removed would not be economically feasible. The emergency diesel generator will only emit 0.05 tons per year of VOC, based on the annual 100 operating hour limitation. An oxidation catalyst system would cost much more than $10,000 per ton of VOC and CO removed.

**Therefore, an oxidation catalyst is not proposed as BACT because it is not economically feasible for the emergency diesel generator.**

**5.7.4.4.2 Combustion Control**
**Energy, Environmental, and Economic Impacts**
Combustion control is accomplished through operational control of the engines; therefore, there are no energy, environmental, or economic impacts associated with this control.

**5.7.4.5 Step 5. Selected VOC Emergency Diesel Generator BACT Determination**
Combustion control was selected as BACT for VOC for the emergency diesel generator; add-on controls are not practical on these small units with limited operation and economic impacts are high. The emergency diesel generator will be able to achieve 0.0007 lb/hp-hr of VOC emissions for the generator on an on-going basis.

**5.7.5 BACT for Greenhouse Gases (GHG) – Emergency Diesel Generator**
The emergency diesel generator is proposed to be used for no more than 100 hours per year. The design of the engine is dictated by the manufacturer, not by the end-user. As such, the Project is limited to commercially available options, which include those engines meeting EPA Tier 3 requirements.

Consistent with its rationale for the BACT determination for greenhouse gas emissions from the combustion turbine, BACT for the emergency diesel generator involves selection of the most efficient stationary emergency generator that can meet the facility's needs. Total greenhouse gas emissions from the emergency diesel generator are estimated at 81.2 tons $CO_2e$ per year. These greenhouse gas emissions are also *de minimus*, when compared to the turbine greenhouse gas emissions.

A Tier 3-certified engine is the most fuel efficient option for these purposes. Further, because emissions of greenhouse gases are directly correlated to operation of the unit, BACT requires that the engine shall only be operated for maintenance, readiness testing, and during emergencies and other periods authorized by the permitting agency and/or the permit.

Because operation of the emergency diesel generator will be limited by permit conditions for reliability-and maintenance related activities and WFEC will be required to keep records of the operation of the emergency diesel generator and its fuel usage, no additional conditions are required to enforce this greenhouse gas BACT determination.

## 5.8 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Cooling Tower

### 5.8.1 Step 1. Identify Potential Control Strategies

Particulate emissions occur from cooling towers as a result of the total solids (suspended and dissolved metals and minerals) in the water droplets entrained in the air stream leaving the cooling tower. These droplets of water (containing particulate) are known as drift. While the majority of the suspended water and particulate are deposited in or near the tower, some of the drift can exit through the top of the tower and enter the air as $PM/PM_{10}/PM_{2.5}$.

Particulate emissions from cooling towers can be controlled by minimizing the amount of drift that occurs and/or minimizing the amount of dissolved solids in the water. This can be accomplished by using high efficiency drift eliminators, a decreased number of cycles of circulating water concentration, or a combination of both. The number of cycles of water concentration is limited by the amount of water available for use, since lower levels of concentration require increased cooling tower blowdown and more water intake to offset the blowdown.

Review of the EPA RBLC database and recent state permits for large-scale cooling towers indicates that high efficiency drift eliminators and limits on TDS concentration in the circulating water are the techniques which set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, which attempt to optimize droplet impingement with minimal pressure drop.

Recent BACT determinations for utility-scale mechanical draft cooling towers are summarized in Table D-7, Appendix D of the application. The commercially available techniques listed to limit drift $PM/PM_{10}/PM_{2.5}$ releases from utility scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005 percent of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce $PM/PM_{10}/PM_{2.5}$ emissions. Compared to "conventional" drift eliminators, high-efficiency drift eliminators reduce the $PM/PM_{10}/PM_{2.5}$ emission rate by more than 90 percent.

In addition to the use of high-efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed cooling tower design for either the GE or Siemens Option will be based on 10 cooling water cycles (i.e., the concentration of dissolved solids in the circulating water will be, on average, 10 times that of the introduced make-up water), and a TDS concentration of 325 ppmw in the make-up water, which translates to a cooling water TDS concentration of 3,250 ppmw.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted by utility-scale combined-cycle plants in arid climates, usually because of concerns other than air emissions, such as the unavailability of water. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

### 5.8.2 Step 2. Identify Technically Feasible Control Technologies

#### 5.8.2.1 High-Efficiency Drift Eliminators

Development of increasingly effective de-entrainment structures has resulted in equipment vendor claims that a cooling tower may be specified to achieve drift releases no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT for cooling towers in current permits.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to “conventional” specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 12-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of $PM/PM_{10}/PM_{2.5}$ abatement.

High-efficiency drift eliminators are considered **technically feasible** for this Project.

#### 5.8.2.2 Total Dissolved Solids (TDS) Circulating Water Limitations

As discussed in the prior sections, management of the tower water balance to control the concentration of dissolved solids in the cooling water is standard operating practice for new cooling towers. Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

Reducing the number of circulations or reducing the TDS of the make-up water are viable options for reducing the particulate emissions from the tower and are considered **technically feasible** for this Project.

#### 5.8.2.3 Non-Evaporative Cooling Tower

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for $PM/PM_{10}/PM_{2.5}$ emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature. Because of process design changes involved in the use of a dry cooling tower, this option is **considered to be technically infeasible** for this Project.

#### 5.8.2.4 Summary of Technically Feasible $PM/PM_{10}/PM_{2.5}$ Controls for the Cooling Tower

The technical feasibility of the control options for the cooling tower is summarized in Table 5-19. The expected performance has been determined considering the design requirements for the cooling tower.

**Table 5-19. Summary of Technically Feasible $PM/PM_{10}/PM_{2.5}$ Technologies for the Cooling Tower**

| Control System | | Technical Feasibility | Comments |
|---|---|---|---|
| Make-up Water Controls | TDS Limit of 3,250 ppm for circulated water | Feasible | Limit based on raw water and number of cycles |
| Drift Eliminators | 0.0005% Drift Efficiency | Feasible | 0.0005% is the lowest drift efficiency available on this cooling tower |
| | 0.001% Drift Efficiency | Feasible | -- |
| Make-up Water Controls Plus Drift Eliminators | TDS Limit of 3,250 ppm for circulated water | Feasible | Limits based on TDS and drift efficiency are both achievable |
| | 0.0005% Drift Efficiency | | |

### 5.8.3 Step 3. Rank the Technically Feasible Control Technologies

This section will rank the commercially available and technically feasible options that could form the basis for a BACT emission limit for $PM/PM_{10}/PM_{2.5}$ from the cooling tower. The technically feasible option of high-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option. There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option. Table 5-20 ranks the control options for the cooling tower.

**Table 5-20. Ranking of $PM/PM_{10}/PM_{2.5}$ Control for the Cooling Tower**

| Control System | | Expected Performance % Reduction | Controlled Emission Rate (GE Option) (lb/hr) | Controlled Emission Rate (Siemens Option) (lb/hr) |
|---|---|---|---|---|
| Make-up Water Controls Plus Drift Eliminators | TDS Limit of 3,250 ppm for circulated water | 99.9995% | 1.14 | 1.28 |
| Drift Eliminators | 0.0005% Drift Efficiency | 99.9995% | 1.14 | 1.28 |
| | 0.001% Drift Efficiency | 99.9990% | 2.28 | 2.56 |
| Make-up Water Controls | TDS Limit of 3,250 ppm for circulated water | Baseline | $2.3 \times 10^5$ | $2.6 \times 10^5$ |

### 5.8.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Selected BACT for $PM/PM_{10}/PM_{2.5}$

Drift eliminators to control drift emissions to 0.0005 percent of the water flow through the cooling tower along with a TDS limit for the circulated water of 3,250 ppm are determined as BACT for particulate matter control on the cooling tower. This represents the highest or "top" option for BACT, and in accordance with EPA guidance, no further control techniques need be considered. Emissions with these controls will be limited to the following for each combustion turbine option:

**GE Option:**

- 5.0 tons per year $PM/PM_{10}/PM_{2.5}$

**Siemens Option:**

- 5.6 tons per year $PM/PM_{10}/PM_{2.5}$

## 5.9 BACT for Volatile Organic Compounds (VOC) – Fuel Oil Storage Tank

### 5.9.1 Steps 1, 2, and 3. Identify Potential Feasible Control Strategies and Rank Control Strategies

The Project will include a 2,800-gallon fuel oil (diesel) storage tank. Diesel fuel has a very low vapor pressure and as such, controls that may be used on high vapor pressure liquids, such as floating roofs, are not as effective at reducing emissions. A fixed roof tank will be required for control of emissions from the fuel oil storage tank and the same is determined to be BACT.

### 5.9.2 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Selected BACT for VOC Emissions

The selected BACT for the fuel oil storage tank is the use of a fixed roof tank. Because emissions are extremely low from this source, this is the only feasible and reasonable control for this small emission source. Emissions will be less than 0.00014 tons per year.

* * * * *

## SECTION VI. AIR DISPERSION MODELING

Since the Project is subject to PSD review, an air dispersion modeling analysis is required for each regulated NSR pollutant that exceeds its PSD significance level. According to the emission estimates for this Project, $NO_x$, CO, VOC, PM/$PM_{10}$/$PM_{2.5}$ and $CO_2$e are subject to PSD review; and, as a result, an air quality analysis was performed for $NO_x$, CO and $PM_{10}$/$PM_{2.5}$ using the EPA-approved AMS/EPA Regulatory Model (AERMOD). Modeling of PM, VOC and $CO_2$e will not be conducted, since there are no modeling thresholds for these pollutants, which conforms to agency guidance.

A pre-project meeting was held with the ODEQ to discuss the modeling protocol that would be used for this Project. The air dispersion modeling protocol and Ozone Limiting Method (OLM) modeling protocol that was submitted to the ODEQ in December 2011 and January 2012, respectively, are presented in Appendix E of the application.

Revision 1 included several changes from the initial modeling that was submitted with the August air permit application. These changes included the following:

- CO emissions from the combustion turbine as a result of the revised BACT analysis (both options remodeled).
- Corrections to the inventory sources as suggested by the ODEQ.
- $NO_2$/NOx in-stack ratios
- $NO_2$ 1-hour background value

Revision 2 (this revision) includes modeling of a larger cooling tower for each combustion turbine option. Increased $PM_{10}$/$PM_{2.5}$ emissions as well as updated modeling parameters and layout were included. The only changes in this version include revised $PM_{10}$ and $PM_{2.5}$ modeling as well as an analysis of secondary $PM_{2.5}$ emissions and potential impacts to $PM_{2.5}$ NAAQS. Background values were also updated to reflect the most recent data from the ODEQ.
These changes are discussed and outlined in this report as well as in the submitted modeling files and background information submitted on the modeling CD.

As with the initial modeling that was submitted, two separate models were set-up and performed for the two options, GE Option and Siemens Option. A summary of the models, the modeling techniques, and modeling results for the Project are discussed in the following sections.

### 6.1 Air Dispersion Model

Air dispersion modeling was performed using the latest version of the AERMOD model (Version 12060). The AERMOD model is an EPA-approved, steady-state, Gaussian air dispersion model that is designed to estimate downwind ground-level concentrations from single or multiple sources using detailed meteorological data. AERMOD is a model currently approved for industrial sources and PSD permits. The ODEQ requested that WFEC demonstrate regulatory compliance through its use.

Major features of the AERMOD model are as follows:

- Plume rise, in stable conditions, is calculated using Briggs equations that consider wind and temperature gradients at stack top and half the distance to plume rise; in unstable conditions, plume rise is superimposed on the displacements by random convective velocities, accounting for updrafts and downdrafts due to momentum and buoyancy as a function of downwind distance for stack emissions
- Plume dispersion receives Gaussian treatment in horizontal and vertical directions for stable conditions and non-Gaussian probability density function in vertical direction for unstable conditions
- AERMOD creates profiles of wind, temperature, and turbulence, using all available measurement levels and accounts for meteorological data throughout the plume depth
- Surface characteristics, such as Bowen ratio, albedo, and surface roughness length, may be specified to better simulate the modeling domain
- Planetary Boundary Layers (PBL) such as friction velocity, Monin-Obukhov length, convective velocity scale, mechanical and convective height, and sensible heat flux may be specified
- AERMOD uses a convective (based upon hourly accumulation of sensible heat flux) and a mechanical mixed layer height
- AERMOD’s terrain pre-processor (AERMAP) provides information for the advanced critical dividing streamline height algorithms and uses National Elevation Dataset (NED) to obtain elevations
- AERMOD uses vertical and horizontal turbulence-based plume growth (from measurements and/or PBL theory) that varies with height and uses continuous growth functions
- AERMOD uses convective updrafts and downdrafts in a probability density function to predict plume interaction with the mixing lid in convective conditions while using a mechanically mixed layer near the ground
- Plume reflection above the lid is considered
- AERMOD models impacts that occur within the cavity regions of building downwash via the use of the plume rise model enhancements (PRIME) algorithm, and then uses the standard AERMOD algorithms for areas without downwash

Details of the modeling algorithms contained in the AERMOD model may be found in the User's Guide for AERMOD. The regulatory default option was selected for this analysis since it met the EPA guideline requirements and ODEQ modeling guidance requirements, with the exception of the 1-hour $NO_2$ modeling. The 1-hour $NO_2$ modeling options selected are detailed in the OLM modeling protocol in Appendix E of this application.

The following default model options, which were discussed in the air dispersion modeling protocol, were used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient
- Rural Dispersion

Further specifications, detailed in the air dispersion modeling protocol submitted to the ODEQ in December 2011, can be found in Appendix E of the application. In addition, the OLM methodology was used for the 1-hour $NO_2$ modeling. An OLM modeling protocol, which discussed the proposed model and the OLM methodology was submitted to the ODEQ in January 2012 and is shown in Appendix E of the application.

**6.2 Model Parameters**

Modeling runs were conducted at full load and partial loads to confirm that operation of the combined-cycle combustion turbine will not result in impacts greater than the NAAQS and PSD Class II Increments. The expected hourly emission rates and modeling parameters for the GE Option combustion turbine and Siemens Option combustion turbine are shown in Table 6-1 and Table 6-2 respectively. These emission rates represent projected worst-case ambient conditions under various operating loads including maximum duct burner emissions and start-up and shutdown emissions. The annual emissions are based on operation at 8,760 hours per year.

**Table 6-1. GE Option - Combustion Turbine Emissions and Modeling Parameters**

| Parameter | 100% Load Plus Duct Burner | 100% Load | 75% Load | 50% Load | Start-up/Shut Down |
|---|---|---|---|---|---|
| $NO_x$ | 23.0 lb/hr | 17.1 lb/hr | 13.9 lb/hr | 12.7 lb/hr | 245.5 lb/hr[A] (45.7 lb/hr[B]) |
| CO | 14.0 lb/hr | 10.4 lb/hr | 8.5 lb/hr | 7.7 lb/hr | 845.44 lb/hr[A] |
| $PM_{10}/PM_{2.5}$ | 31.8 lb/hr | 22.1 lb/hr | 21.4 lb/hr | 21.1 lb/hr | 30.44 lb/hr |
| Stack Temperature | 193 ºF | 221 ºF | 208 ºF | 199 ºF | 199 ºF |
| Exit Velocity | 54.1 ft/s[C] | 55.4 ft/s | 41.1 ft/s | 36.5 ft/s | 36.5 ft/s |
| Stack Height | 130 feet | 130 feet | 130 feet | 130 feet | 130 feet |
| Stack Diameter | 22 feet | 22 feet | 22 feet | 22 feet | 22 feet |

[A] Maximum 1-hour start-up emissions
[B] Maximum annual emissions including 365 start-ups averaged over 8,760 hours per year
[C] ft/s = feet per second

**Table 6-2. Siemens Option - Combustion Turbine Emissions and Modeling Parameters**

| Parameter | 100% Load Plus Duct Burner | 100% Load | 75% Load | 50% Load | Start-up/Shut Down |
|---|---|---|---|---|---|
| $NO_x$ | 23.8 lb/hr | 18.0 lb/hr | 14.1 lb/hr | 10.8 lb/hr | 245.5 lb/hr[A] (46.38 lb/hr[B]) |
| CO | 14.5 lb/hr | 11.0 lb/hr | 8.6 lb/hr | 6.6 lb/hr | 845.44 lb/hr[A] |
| $PM_{10}/PM_{2.5}$ | 31.6 lb/hr | 22.2 lb/hr | 19.3 lb/hr | 18.5 lb/hr | 30.32 lb/hr |
| Stack Temperature | 193 ºF | 221 ºF | 208 ºF | 199 ºF | 199 ºF |
| Exit Velocity | 59.2 ft/s | 60.7 ft/s | 45.4 ft/s | 37.8 ft/s | 37.8 ft/s |

| | | | | | |
|---|---|---|---|---|---|
| Stack Height | 130 feet | 130 feet | 130 feet | 130 feet | 130 feet |
| Stack Diameter | 22 feet | 22 feet | 22 feet | 22 feet | 22 feet |

[A] Maximum 1-hour start-up emissions
[B] Maximum annual emissions including 365 start-ups averaged over 8,760 hours per year

The expected hourly emission rates and modeling parameters for the emergency diesel generator and cooling tower are shown in Table 6-3.Table 6-3. The emergency diesel generator will be the same size and have the same emissions for both combustion turbine options. The cooling tower will be slightly different for both combustion turbine options. Annual emissions for the emergency diesel generator were based on operation of 100 hours per year.

**Table 6-3. Emergency Diesel Generator and Cooling Tower Emissions and Modeling Parameters**

| Parameter | Emergency Diesel Generator (Both Options) | GE Option Cooling Tower | Siemens Option Cooling Tower |
|---|---|---|---|
| $NO_x$ | 17.43 lb/hr (0.20 lb/hr[A]) | -- | -- |
| CO | 7.38 lb/hr (0.08 lb/hr[A]) | -- | -- |
| PM/ $PM_{10}$ | 0.44 lb/hr (0.01 lb/hr[A]) | 0.10 lb/hr per cell | 0.11 lb/hr per cell |
| Stack Temperature | 890 ºF | 53.2 ºF | 53.2 ºF |
| Exit Velocity | 385.1 ft/s | 20.5 ft/s | 20.9 ft/s |
| Stack Height | 15 feet | 47.2 feet | 59.0 feet |
| Stack Diameter | 0.67 feet | 32 feet | 32.2 feet |

[A] Equivalent lb/hr emissions averaged over 8,760 hours per year, based on operation of 100 hours.

### 6.2.1 Good Engineering Practice

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in OAC 252:100-8-1.5. As defined by the regulations, GEP height is calculated as the greater of 65 meters (measured from the ground level elevation at the base of the stack) or the height resulting from the following formula:

$$GEP = H + 1.5L$$

Where

H = the height of nearby structure(s) measured from the ground level elevation at the base of the stack; and

L = the lesser dimension (height or projected width) of nearby structure(s) (i.e., building height or the greatest crosswind distance of the building - also known as maximum projected width).

To meet stack height requirements, the point sources were evaluated in terms of their proximity to nearby structures. The purpose of this evaluation was to determine if the discharge from the stack will become caught in the turbulent wake of a building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. The ODEQ provides guidance for determining whether building downwash will occur in OAC 252: 100-8-1.5. The downwash analysis was performed consistent with the methods prescribed in OAC 252:100-8-1.5.

Calculations for determining the direction-specific downwash parameters were performed using the most current version of the EPA's Building Profile Input Program – Plume Rise Model Enhancements (Version 04274), otherwise referred to as the BPIP-PRIME downwash algorithm. The BPIP-PRIME model provides direction-specific building dimensions to evaluate downwash conditions. The Mooreland Generating Station is located in a rural area and the only buildings that could potentially affect emissions from the proposed Project are the on-site structures.

After running the BPIP-PRIME model, it was determined that the GEP stack height for this Project will not exceed 65 meters for both combustion turbine options. A stack height of 130 feet (39.62 meters) was used in the AERMOD modeling for both combustion turbine options.

## 6.3 Modeling Methodology and Parameters

### 6.3.1 Receptor Grid

The overall purpose of the modeling analysis is to quantify the ground-level concentrations from the operation of the proposed Project to determine if the Project will result in, or contribute to, concentrations above the NAAQS and/or PSD Class II Increments. The modeling runs for both combustion turbine options were conducted using the AERMOD model in simple and complex terrain mode within a 15-by-15 kilometer Cartesian grid to determine the significant impact area for each pollutant. The grid incorporates the following spacing between receptors: 50 meter out to 0.1 kilometers, 100 meter out to two kilometers, 250 meter out to five kilometers, and 1,000 meter out to 15 kilometers. Receptors were also placed along the fence line boundary at a spacing of 50 meters. The significant impact area exceeded fifteen kilometers for the 1-hour $NO_2$ averaging period for both combustion turbine options; therefore, the grid was extended to a 50-by-50 kilometer grid. The significant impact area did not exceed 15 kilometers for all other pollutants and averaging periods and the receptor grid was not extended for both combustion turbine options.

The appropriate U.S. Geological Survey (USGS) Digital Elevation Model (DEM) terrain files were used to obtain the necessary receptor elevations. North American Datum of 1983 (NAD 83) was used to develop the Universal Transverse Mercator (UTM) coordinates for this project.

AERMOD has a terrain preprocessor (AERMAP) which uses gridded terrain data for the modeling domain to calculate not only a XYZ coordinate, but a representative terrain-influence height associated with each receptor location selected. This terrain-influenced height is called the height scale and is separate for each individual receptor. AERMAP (Version 11103) utilized the electronic DEM terrain data to populate the model with receptor elevations.

### 6.3.2 Meteorological Data

Meteorological data obtained from the ODEQ was used for the modeling analysis. Integrated Surface Hourly meteorological data from West Woodward, Oklahoma (station # 722152-99999) was used for years 2006 to 2008. For years 2009 and 2010, Integrated Surface Hourly meteorological data from Gage Airport, Oklahoma (station # 723527-13975) was used. For all meteorological years (2006 to 2010), upper air data from the Dodge City Regional Airport, Kansas (station # 724510-13985) was used. For all meteorological years, meteorological data from the Woodward Oklahoma Mesonet Site (107) was incorporated as on-site data. Oklahoma

Mesonet data was provided to the ODEQ courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and the University of Oklahoma and supported by the taxpayers of Oklahoma.

A profile base elevation of 625 meters was used. The dominant wind direction is shown in Figure 6-3 in Appendix F of the application.

### 6.3.3 Model Parameters

Based on the Auer scheme, the existing land use for a three-kilometer area surrounding the Mooreland Generating Station is more than 50 percent rural, and the population density is less than 750 people per square kilometer for the same area. Therefore, rural dispersion coefficients were used in the AERMOD models.

### 6.3.4 Significant Impact Area Determination

The AERMOD models for both combustion turbine options were run for the Project using the worst-case impact scenario for the combustion turbine and associated equipment. If any modeled pollutant resulted in impacts below the significance levels for each averaging period, no further modeling for that pollutant and averaging period was required to determine compliance with the NAAQS or PSD Class II Increments. However, if the modeling predicted impacts at or above the modeling significance level for any pollutant, a cumulative analysis including all point sources within the radius of impact (ROI) was required for that pollutant and averaging period.

### 6.3.5 NAAQS and PSD Class II Increment Analysis

For the NAAQS and PSD Class II increments, all major stationary sources that emit pollutants subject to this analysis and located within the ROI of the Mooreland Generating Station were addressed. The ODEQ provided the inventory of sources located in the ROI. The existing Mooreland Generating Station sources are located in Appendix C of the application and the other inventory sources provided by the ODEQ are located in Appendix G of the application. Background concentrations were included for NAAQS modeling compliance determinations. The background concentrations provided by the ODEQ are shown in Table 6-4.

**Table 6-4. Background Level**

| Pollutant | Averaging Period | Year | Background (μg/m$^3$) | Site |
|---|---|---|---|---|
| $NO_2$ | 1-hour | 2009-11 | 38.5 | 40-135-9002, 40101-9001 |
| $PM_{10}$ | 24-hour | 2009-11 | 45.0 | 40-109-1037 |
| $PM_{2.5}$ | Annual | 2008-10 | 9.3 | 40-015-9008 |
| | 24-hour | 2008-10 | 20.0 | 40-015-9005 |

### 6.3.6 Ambient Monitoring

The modeling analysis for emission sources at the Mooreland Generating Station addresses the pre-construction monitoring provision of the PSD regulations. The regulations specify significant monitoring levels for each PSD pollutant that triggers the requirement to perform one year of pre-construction ambient air monitoring. For any impacts predicted to be below the monitoring *de minimis* levels, WFEC requests pre-construction ambient air monitoring not be required. For any predicted concentrations reaching or exceeding the monitoring *de minimis* levels, WFEC plans to meet all pre-construction monitoring requirements stated in the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA). The NAAQS, modeling/monitoring significance levels, and PSD Class II Increment thresholds for the modeled pollutants are shown in Table 6-5.[5]

**Table 6-5. NAAQS, Significance Levels and PSD Class II Increment (μg/m$^3$)**

| Pollutant | Averaging Period | NAAQS | Modeling Significance Level | Monitoring Significance Level | PSD Class II Increment |
|---|---|---|---|---|---|
| $NO_2$ | annual | 100 | 1 | 14 | 25 |
| | 1-hour | 188.7 | 7.5 | NA | NA |
| CO | 8-hour | 10,000 | 500 | 575 | NA |
| | 1-hour | 40,000 | 2,000 | NA | NA |
| $PM_{10}$ | annual | NA | 1 | NA | 17 |
| | 24-hour | 150 | 5 | 10 | 30 |
| $PM_{2.5}$ | annual | 12 | 0.3 | NA | 4 |
| | 24-hour | 35 | 1.2 | 4 | 9 |

### 6.3.7 $NO_2$ Modeling – Multi-Tiered Screening Approach

The AERMOD model predicts ground-level concentrations of any generic pollutant without chemical transformations. Thus, the modeled $NO_X$ emission rate will give ground-level modeled concentrations of $NO_X$. NAAQS values are presented as $NO_2$.

The EPA has a three-tier approach to modeling $NO_2$ concentrations.

- Tier I – total conversion, or all $NO_x$ = $NO_2$
- Tier II – use a default $NO_2/NO_x$ ratio
- Tier III – case-by-case detailed screening methods, such as OLM and Plume Volume Molar Ratio Method (PVMRM)

Initial modeling was performed using both Tier I and Tier II methodologies. It was determined from these modeling iterations that less conservative methods for determining 1-hour $NO_2$ compliance would be needed for this project. Therefore, the ambient impact of the 1-hour $NO_X$ predicted by the models was screened using the Tier III – OLM. An OLM modeling protocol, which discussed the proposed model to be used and the OLM methodology was submitted to the ODEQ in January 2012 and is shown in Appendix E of the application for reference. The protocol was approved by AQD.

[5] The pollutants that are allowed one NAAQS exceedance per year and one PSD Class II Increment exceedance per year are:NAAQS 1-hour and 8-hour CO and all short term increments or Increment; 24-hour $PM_{10}$ and 24-hour PM $_{2.5}$.

The Ozone Limiting Method (OLM) utilizes the in-stack ratio of $NO_X$ to $NO_2$ to determine the total conversion of $NO_X$ to $NO_2$. Modeling for the new 1-hour standard complied with the EPA's guidance "General Guidance for Implementing the 1-hour $NO_2$ NAAQS in PSD permits, Including the Interim 1-hour $NO_2$ SIL" dated June 28, 2010.

For the Tier III analysis, the ambient equilibrium ratio was set at 0.9 and hourly ozone data from the nearest ozone monitor located in Seiling, Oklahoma was input into AERMOD. AERMOD then used that data to predict the conversion of $NO_X$ to $NO_2$. The ozone data was hourly data from the same years as those being used for the modeling. For the Tier III analysis, the in-stack ratio for each source was evaluated and set at the levels listed below.

**In-Stack $NO_2$/$NO_X$ Ratios**

| Source Type | Ratio |
|---|---|
| 4SLB Engines | 0.35 |
| 2SLB Engines | 0.50 |
| 4SRB Engines | 0.05 |
| Turbines | 0.20 |
| Heaters/Boilers | 0.10 |

Using these in-stack ratios, the modeled impacts of the nearby sources plus background still exceed the 1-hour $NO_2$ NAAQS. Based on the modeling analysis, the impacts from the proposed facility did not cause or contribute to a violation of the NAAQS.

The Tier III OLM was not applied to the $NO_X$ annual averaging period modeled impacts. The annual ambient impact of $NO_X$ predicted by the model was screened using Tier II, the Ambient Ratio Method (ARM). Tier II of the ARM allows the use of an empirically derived $NO_2$/$NO_X$ ratio of 0.75, which means that approximately 75 percent of the $NO_X$ emissions will be converted to NO2, the regulated pollutant.

## 6.4 GE Option Significance Model Results

### 6.4.1 GE Option $NO_2$ Results

After examining the GE Option modeling results at all load levels, it was determined that no exceedances of the annual $NO_2$ modeling significance level occurred, and that no further modeling was required. The predicted impacts were lower than the ambient air monitoring *de minimis* level and no pre-construction monitoring will be required.

The GE Option model predicted that impacts greater than the 1-hour $NO_2$ modeling significance level occurred, and refined modeling would be required. The maximum modeled concentration for the $NO_2$ 1-hour and annual average period is given in Table 6-6.

### 6.4.2 GE Option CO Results

After examining the GE Option modeling results at all load levels, it was determined that no exceedances of the 1-hour or 8-hour CO modeling significance levels occurred, and that no further modeling was required. Also, for the GE Option, the 8-hour predicted impacts were lower than the ambient air monitoring *de minimis* level and no pre-construction monitoring will be required. The maximum modeled concentrations for CO are given in Table 6-6.

### 6.4.3 GE Option $PM_{2.5}/PM_{10}$ Results

After examining the GE Option modeling results at all load levels, it was determined that no exceedances of the annual $PM_{10}$ modeling thresholds occurred; therefore, no further modeling was required. The model predicted that impacts greater than the annual $PM_{2.5}$, 24-hour $PM_{2.5}$ and 24-hour $PM_{10}$ modeling significance levels occurred for the GE Option, and refined modeling would be required. The GE Option 24-hour modeling impacts for $PM_{2.5}$ and $PM_{10}$ are greater than the ambient air monitoring *de minimis* levels. However, WFEC requests that existing monitoring data from the monitor located in North OKC (monitor number 400159008) be used for existing ambient levels of $PM_{2.5}$ and the monitor located in Custer County, near Clinton (monitor number 400390852) be used for existing ambient levels of $PM_{10}$ in the area. These monitors have recent data and are located in areas that are similar and representative of the $PM_{2.5}$ and $PM_{10}$ levels in the Mooreland area. The maximum impacts from the proposed Project (GE Option) are listed in Table 6-6.

The facility was significant for $NO_X$ precursors (> 40 TPY) for the formation of secondary $PM_{2.5}$. Since the H1H was used to model compliance with the NAAQS rather than the H8H, the difference between the two values is what was assigned to the secondary formation of $PM_{2.5}$ within the modeling domain. Based on the difference between these two values secondary formation from the facility was attributed 2.54 μg/m$^3$. If we assume a conservative $NO_3/NO_X$ ratio of 1:100, then secondary formation of $PM_{2.5}$ would amount to approximately 2.0 TPY which would have an estimated impact of 0.08 μg/m$^3$ which is accounted for by using the H1H rather than the design value from the modeling. Also, since the maximum impact in the modeling domain, which occurs at the facility fenceline, is used to determine compliance with the NAAQS for the whole domain, and secondary formation is expected to occur much farther from the facility the analysis of secondary formation using the H1H is adequate enough to account for secondary formation of $PM_{2.5}$ from the proposed facility.

Available monitoring data was complete and adequate enough to account for formation of secondary $PM_{2.5}$ emissions because it is "within the time period that maximum pollutant concentrations would occur" and within a similar rural area with similar emission densities, climate, and terrain. Not to mention that some consideration should be given to the potential for some double counting of the impacts from modeled emissions that may be reflected in the background monitoring. Given emission levels from the facility and local emission inventories no further analyses of secondary formation were warranted.

**Table 6-6. GE Option - Maximum Modeled Concentrations from Project**

| Pollutant | Averaging Period | UTM Coordinates[A] | | Year | GE Option Impact (μg/m$^3$)[B] | Modeling Significance Level (μg/m$^3$) | Monitoring Significance Level (μg/m$^3$) |
|---|---|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | | | |
| $NO_2$ | Annual[C, D] | 480000 | 4033000 | 2010 | 0.85 | 1 | 14 |
| | 1-hour[C] | 479526 | 4032476 | 5 yrs | 126.5 | 7.5 | -- |
| CO | 1-hour | 479758 | 4032671 | 2008 | 1,032 | 2,000 | -- |
| | 8-hour | 480000 | 4032900 | 2008 | 494.1 | 500 | 575 |
| $PM_{10}$ | Annual[C, D] | 480000 | 4033000 | 2010 | 1.98 | 1 | -- |
| | 24-hour | 480000 | 4032900 | 2008 | 14.53 | 5 | 10 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| $PM_{2.5}$ | Annual[C, D] | 480000 | 4033000 | 2010 | 1.98 | 0.3 | -- |
| | 24-hour | 480000 | 4032900 | 2008 | 14.53 | 1.2 | 4 |

[A] - NAD 83; [B] - Highest 1st High; [C] - Averaged over five years; [D] - Based on averaging of short term emissions.

The results of the GE Option modeling indicate that the impacts of the 1-hour and 8-hour CO, annual $NO_2$ averaging periods from the proposed Project will not result in a significant impact at any location. No further modeling is required for a PSD pollutant if the modeled impacts are below the significance levels.

The GE Option modeling analyses indicate that the proposed Project's emissions will exceed the PSD modeling significance thresholds for the $NO_2$ 1-hour, $PM_{10}$ 24-hour, $PM_{2.5}$ annual, and $PM_{2.5}$ 24-hour averaging periods. A refined modeling analysis was therefore conducted to demonstrate compliance with the NAAQS and PSD Class II Increments for these pollutants.

Model input and output files for each pollutant are provided in Appendix G of the application on CD-ROM for the GE Option. In addition, GE Option area plots with concentration contour plots of each pollutant are shown in Figures 6-4 to 6-11 in Appendix F of the application.

### 6.5 GE Option PSD Class II Increment Modeling

A GE Option refined modeling analysis was conducted for the $PM_{10}$ 24-hour and $PM_{2.5}$ annual and 24-hour averaging periods to demonstrate compliance with the PSD Class II Increments. An inventory of sources within the expected ROI was used in the refined analysis. This inventory of sources and modeled parameters can be seen in Appendix G of the application.

There were no modeled PSD Increment exceedances for these pollutants and averaging periods. As such, it was determined that there is enough available $PM_{10}$ and $PM_{2.5}$ PSD Class II Increment to construct and operate the proposed project for the GE Option. The results of the PSD Class II Increment analysis are shown below in Table 6-7. The second highest high was used for the 24-hour averaging periods.

**Table 6-7. GE Option - $PM_{2.5}$ and $PM_{10}$ Increment Modeling Results**

| Pollutant | Averaging Period | UTM Coordinates[A] | | Year | GE Option Impact (µg/m³) | Class II Increment (µg/m³) |
|---|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | | |
| $PM_{10}$ | Annual[C, D] | 480,800 | 4,033,000 | 2010 | 15.91 | 17 |
| | 24-hour[B] | 480,800 | 4,033,000 | 2008 | 12.04 | 30 |
| $PM_{2.5}$ | Annual[C, D] | 480,000 | 4,033,000 | 5 yrs | 1.55 | 4 |
| | 24-hour[B] | 480,000 | 4,033,000 | 2008 | 8.17 | 9 |

[A] - NAD 83; [B] - Highest 2nd High; [C] - Averaged over five years; [D] - Based on averaging of short term emissions.

The GE Option model input and output files are provided on CD-ROM in Appendix G of the application. In addition area plots with concentration contour plots are shown in Figures 6-12 to 6-14 in Appendix E of the application.

## 6.6 GE Option NAAQS Modeling

A refined modeling analysis was conducted for the 1-hour $NO_2$ averaging period, 24-hour $PM_{10}$ averaging period, and the annual and 24-hour $PM_{2.5}$ averaging periods to demonstrate compliance with the NAAQS for the GE Option.

There were no modeled NAAQS exceedances for the $PM_{10}$ 24 hour averaging period. There were modeled NAAQS exceedances for the $NO_2$ 1-hour averaging period and the $PM_{2.5}$ annual and 24-hour averaging periods. Further analysis demonstrated that the proposed Project is not significant at the receptors that exceed the NAAQS for the GE Option. Details of the further analysis can be found in Appendix G of this application. Therefore, the proposed Project will be in compliance with the NAAQS for the GE Option. The GE Option NAAQS analysis modeling results are shown in Table 6-8.

**Table 6-8. GE Option - NAAQS Modeling Results**

| Pollutant & Averaging Period | | UTM Coordinates[A] | | GE Option Impact (µg/m³) | Background (µg/m³) | Total (µg/m³) | NAAQS (µg/m³) |
|---|---|---|---|---|---|---|---|
| | | Easting meters | Northing (meters) | | | | |
| $NO_2$ | 1-hour | 486,000 | 4,033,000 | 524.8 | 38.5 | 563.3[B] | 188 |
| $PM_{10}$ | 24-hour | 480,700 | 4,032,600 | 68.7 | 45.0 | 113.7 | 150 |
| $PM_{2.5}$ | Annual[B] | 480,800 | 4,032800 | 4.7 | 9.3 | 14.0[B] | 12 |
| $PM_{2.5}$ | 24-hour | 480,700 | 4,032,700 | 29.5 | 20.0 | 49.5[B] | 35 |

[A] - NAD 83; [B] – The Mooreland Station, including the Project, is not significant at any modeled exceedence.

The NAAQS thresholds were compared to the following highs shown in Table 6-9 for each averaging period.

**Table 6-9. Modeled Highs**

| Pollutant | Averaging Period | Modeled High |
|---|---|---|
| $NO_2$ | 1-hour | 98th Percentile |
| $PM_{10}$ | 24-hour | Highest 6th High |
| $PM_{2.5}$ | Annual | Averaged over 5 Years |
| | 24-hour | Highest 1st High |

The Mooreland Generating Station, including the Project, is not significant at any modeled exceedance. The GE Option model input and output files (including the additional analysis) are provided on CD-ROM in Appendix G of the application. In addition, GE Option area plots with concentration contour plots are shown in Figures 6-15 to 6-18 in Appendix E of the application.

## 6.7 GE Option PSD Class I Analysis

The nearest Class I area to the Mooreland Generating Station is the Wichita Mountains Wilderness in southwestern Oklahoma. The Wichita Mountains Wilderness is approximately 200 kilometers from the Mooreland site and is the only Class I area within 300 kilometers of the Mooreland site. To determine if further analysis is required for the Class I area analysis modeled impacts at receptors placed 50 kilometers in the direction of the Class I area were compared to the Class I significance thresholds. The Class II modeled impacts in comparison to the Class I significance threshold is shown in Table 6-10. Based on the analysis, it was determined that the impacts from the proposed Project will not significantly impact the Wichita Mountains Wilderness and does not require further analysis for the GE Option.

**Table 6-10. GE Option - Class II Modeled Impacts and Class I Significant Impact Level**

| Pollutant | Averaging Time | UTM Coordinates[A] | | Maximum GE Impact at 50 km (µg/m³) | Class I Significant Impact Level (µg/m³) |
|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | |
| $SO_2$ | 3-hour | 492,400 | 3,982,200 | 0.060 | 1.0 |
| | 24-hour | 492,400 | 3,982,200 | 0.017 | 0.2 |
| | Annual | 492,400 | 3,982,200 | 0.001 | 0.1 |
| $PM_{10}$ | 24-hour | 492,400 | 3,982,200 | 0.063 | 0.3 |
| | Annual | 492,400 | 3,982,200 | 0.003 | 0.2 |
| $PM_{2.5}$ | 24-hour | 492,400 | 3,982,200 | 0.063 | 0.07 |
| | Annual | 492,400 | 3,982,200 | 0.003 | 0.06 |
| $NO_2$[B] | Annual | 492,400 | 3,982,200 | 0.005 | 0.1 |

[A] - NAD 83; [B] - Modeled as $NO_X$

## 6.8 Siemens Option Significance Model Results

### 6.8.1 Siemens Option $NO_2$ Results

After examining the Siemens Option modeling results at all load levels, it was determined that no exceedances of the annual $NO_2$ modeling significance level occurred, and that no further modeling was required. The predicted impacts were lower than the ambient air monitoring *de minimis* level and no pre-construction monitoring will be required.

The Siemens Option model predicted that impacts greater than the 1-hour $NO_2$ modeling significance level occurred, and refined modeling would be required. The maximum modeled concentration for the $NO_2$ 1-hour and annual average period is given in Table 6-11.

### 6.8.2 Siemens Option CO Results

After examining the Siemens Option modeling results at all load levels, it was determined that no exceedances of the 1-hour or 8-hour CO modeling significance levels occurred, and that no further modeling was required. Also, for the Siemens Option, the 8-hour predicted impacts were lower than the ambient air monitoring *de minimis* level and no pre-construction monitoring will be required. The maximum modeled concentrations for CO are given in Table 6-11.

### 6.8.3 Siemens Option $PM_{2.5}$/$PM_{10}$ Results

After examining the Siemens Option modeling results at all load levels, it was determined that no exceedances of the annual $PM_{10}$ modeling thresholds occurred; therefore, no further modeling was required. The model predicted that impacts greater than the annual $PM_{2.5}$, 24-hour $PM_{2.5}$, annual $PM_{10}$ and 24-hour $PM_{10}$ modeling significance levels occurred for the Siemens Option, and refined modeling would be required. The Siemens Option 24-hour modeling impacts for $PM_{2.5}$ and $PM_{10}$ are greater than the ambient air monitoring *de minimis* levels. However, WFEC requests that existing monitoring data from the monitor located in Enid, OK (monitor number 400470554) be used for existing ambient levels of $PM_{2.5}$ and the monitor located in Custer County, near Clinton (monitor number 400390852) be used for existing ambient levels of $PM_{10}$ in the area. These monitors have recent data and are located in areas that are similar and representative of the $PM_{2.5}$ and $PM_{10}$ levels in the Mooreland area. The maximum impacts from the proposed Project are listed in Table 6-11.

The facility was significant for $NO_X$ precursors (> 40 TPY) for the formation of secondary $PM_{2.5}$. Since the H1H was used to model compliance with the NAAQS rather than the H8H, the difference between the two values is what was assigned to the secondary formation of $PM_{2.5}$ within the modeling domain. Based on the difference between these two values secondary formation from the facility was attributed 2.54 $\mu g/m^3$. If we assume a conservative $NO_3/NO_X$ ratio of 1:100, then secondary formation of $PM_{2.5}$ would amount to approximately 2.0 TPY which would have an estimated impact of 0.08 $\mu g/m^3$ which is accounted for by using the H1H rather than the design value from the modeling. Also, since the maximum impact in the modeling domain, which occurs at the facility fenceline, is used to determine compliance with the NAAQS for the whole domain, and secondary formation is expected to occur much farther from the facility the analysis of secondary formation using the H1H is adequate enough to account for secondary formation of $PM_{2.5}$ from the proposed facility.

Available monitoring data was complete and adequate enough to account for formation of secondary $PM_{2.5}$ emissions because it is "within the time period that maximum pollutant concentrations would occur" and within a similar rural area with similar emission densities, climate, and terrain. Not to mention that some consideration should be given to the potential for some double counting of the impacts from modeled emissions that may be reflected in the background monitoring. Given emission levels from the facility and local emission inventories no further analyses of secondary formation were warranted.

**Table 6-11. Siemens Option - Maximum Modeled Concentrations**

| Pollutant | Averaging Period | UTM Coordinates[A] | | Year | Siemens Option Impact (μg/m³) | Modeling Significance Level (μg/m³) | Monitoring Significance (μg/m³) |
|---|---|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | | | |
| $NO_2$ | Annual[C, D] | 480,000 | 4,033,000 | 2010 | 0.82 | 1 | 14 |
| | 1-hour[C] | 479,526 | 4,032,476 | 5 yrs | 125.3 | 7.5 | -- |
| CO | 1-hour | 479,758 | 4,032,671 | 2008 | 1,006 | 2,000 | -- |
| | 8-hour | 480,000 | 4,032,900 | 2008 | 474.8 | 500 | 575 |
| $PM_{10}$ | Annual[C, D] | 480,057 | 4,032,613 | 2010 | 2.04 | 1 | -- |
| | 24-hour | 480,000 | 4,032,900 | 2008 | 13.87 | 5 | 10 |
| $PM_{2.5}$ | Annual[C, D] | 480,057 | 4,032,613 | 2010 | 2.04 | 0.3 | -- |
| | 24-hour | 480,000 | 4,032,900 | 2008 | 13.87 | 1.2 | 4 |

[A] - NAD 83; [B] - Highest 1st High; [C] - Averaged over five years; [D] - Based on averaging of short term emissions.

The results of the Siemens Option modeling indicate that the impacts of the 1-hour and 8-hour CO, annual $NO_2$, and annual $PM_{10}$ averaging periods from the proposed Project will not result in a significant impact at any location. No further modeling is required for a PSD pollutant if the modeled impacts are below the significance levels.

The Siemens Option modeling analyses indicate that the proposed Project's emissions will exceed the PSD modeling significance thresholds for $NO_2$ 1-hour, $PM_{10}$ 24-hour, $PM_{2.5}$ annual, and $PM_{2.5}$ 24-hour averaging periods. A refined modeling analysis was therefore conducted to demonstrate compliance with the NAAQS and PSD Class II Increments.

Model input and output files for each pollutant are provided in Appendix G of this application on CD-ROM for the Siemens Option. In addition, Siemens Option area plots with concentration contour plots of each pollutant are shown in Figures 6-19 to 6-26 in Appendix F of the application.

### 6.9 Siemens Option PSD Class II Increment Modeling

A Siemens Option refined modeling analysis was conducted for the $PM_{10}$ 24-hour and $PM_{2.5}$ annual and 24-hour averaging periods to demonstrate compliance with the PSD Class II Increments. An inventory of sources within the expected ROI was used in the refined analysis. This inventory of sources and modeled parameters can be seen in Appendix G of the application.

There were no modeled PSD Increment exceedances for the pollutants and averaging periods modeled for the Siemens Option. As such, it was determined that there is enough available $PM_{10}$

and $PM_{2.5}$ PSD Class II Increment to construct and operate the proposed Project for the Siemens Option.

The results of the PSD Class II Increment analysis are shown below in Table 6-12 for the Siemens Option. The second highest high was used for the 24-hour averaging periods.

**Table 6-12. Siemens Option - $PM_{2.5}$ and $PM_{10}$ Increment Modeling Results**

| Pollutant | Averaging Period | UTM Coordinates[A] | | Year | Siemens Option Impact ($\mu g/m^3$) | PSD Class II Increment ($\mu g/m^3$) |
|---|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | | |
| | Annual[C, D] | 480,800 | 4,032,800 | 2010 | 15.92 | 17 |
| $PM_{10}$ | 24-hour[B] | 480,000 | 4,033,000 | 2008 | 11.83 | 30 |
| $PM_{2.5}$ | Annual[C, D] | 480,057 | 4,032,613 | 2010 | 2.07 | 4 |
| | 24-hour[B] | 480,000 | 4,033,000 | 2008 | 7.96 | 9 |

[A] - NAD 83; [B] - Highest 2nd High; [C] - Averaged over five years; [D] - Based on averaging of short term emissions.

The Siemens Option model input and output files are provided on CD-ROM in Appendix G of the application. In addition area plots with concentration contour plots are shown in Figures 6-27 to 6-29 in Appendix E of the application.

### 6.10 Siemens Option NAAQS Modeling

A refined modeling analysis was conducted for the 1-hour $NO_2$ averaging period, 24-hour $PM_{10}$ averaging period, and the annual and 24-hour $PM_{2.5}$ averaging periods to demonstrate compliance with the NAAQS for the Siemens Option.

There were no modeled NAAQS exceedances for the $PM_{10}$ 24 hour averaging period. There were modeled NAAQS exceedances for the $NO_2$ 1-hour averaging period and the $PM_{2.5}$ annual and 24-hour averaging periods. Further analysis demonstrated that the proposed project is not significant at the receptors that exceed the NAAQS for the Siemens Option. Details of the further analysis can be found in Appendix G of the application. Therefore, the proposed Project will be in compliance with the NAAQS for the Siemens Option. The Siemens Option NAAQS analysis modeling results are shown in Table 6-13.

**Table 6-13. Siemens Option - NAAQS Modeling Results**

| Pollutant | Averaging Period | UTM Coordinates[A] | | Siemens Option Impact ($\mu g/m^3$) | Background ($\mu g/m^3$) | Total ($\mu g/m^3$) | NAAQS ($\mu g/m^3$) |
|---|---|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | | | |
| $NO_2$ | 1-hour | 499,000 | 4,000,000 | 522.2 | 38.5 | 560.7[B] | 188 |
| $PM_{10}$ | 24-hour | 480,800 | 4,032,800 | 68.7 | 45.0 | 113.7 | 150 |
| $PM_{2.5}$ | Annual | 480,800 | 4,032,800 | 4.66 | 9.3 | 13.96[B] | 12 |
| $PM_{2.5}$ | 24-hour | 480,000 | 4,032,900 | 29.5 | 20.0 | 49.5[B] | 35 |

[A] NAD 83 [B] The Moreland Station, including the Project, is not significant at any modeled exceedance.

The Mooreland Generating Station, including the Project, is not significant at any modeled exceedance. The NAAQS thresholds were compared to the highs shown in Table 6-9 for each averaging period.

The Siemens Option model input and output files (including the additional analysis) are provided on CD-ROM in Appendix G of the application. In addition, Siemens Option area plots with concentration contour plots are shown in Figures 6-30 to 6-33 in Appendix E of the application.

### 6.11 Siemens Option PSD Class I Analysis

The nearest Class I area to the Mooreland Generating Station is the Wichita Mountains Wilderness in southwestern Oklahoma. The Wichita Mountains Wilderness is approximately 200 kilometers from the Mooreland site and is the only Class I area within 300 kilometers of the Mooreland site. To determine if further analysis is required for the Class I area analysis modeled impacts at receptors placed 50 kilometers in the direction of the Class I area were compared to the Class I significance thresholds. The Class II modeled impacts in comparison to the Class I significance threshold is shown in Table. Based on the analysis, it was determined that the impacts from the proposed Project will not significantly impact the Wichita Mountains Wilderness and does not require further analysis for the Siemens Option.

**Table 6-14. Siemens Option - Class II Modeled Impacts and Class I Significant Impact Level**

| Pollutant | Averaging Period | UTM Coordinates[A] | | Maximum Siemens Option Impact at 50 km ($\mu g/m^3$) | Class I Significant Impact Level ($\mu g/m^3$) |
|---|---|---|---|---|---|
| | | Easting (meters) | Northing (meters) | | |
| $SO_2$ | 3-hour | 492,400 | 3,982,200 | 0.058 | 1.0 |
| | 24-hour | 492,400 | 3,982,200 | 0.016 | 0.2 |
| | Annual | 492,400 | 3,982,200 | 0.0009 | 0.1 |
| $PM_{10}$ | 24-hour | 492,400 | 3,982,200 | 0.062 | 0.3 |
| | Annual | 492,400 | 3,982,200 | 0.0039 | 0.2 |
| $PM_{2.5}$ | 24-hour | 492,400 | 3,982,200 | 0.062 | 0.07 |
| | Annual | 492,400 | 3,982,200 | 0.0039 | 0.06 |
| $NO_2$[B] | Annual | 492,400 | 3,982,200 | 0.005 | 0.1 |

[A] NAD 83; [B] Modeled as $NO_x$

### 6.12 Analysis of Secondary PM2.5 Formation – Both Options

In addition to direct emissions of $PM_{2.5}$, other pollutants, chiefly NOx and $SO_2$, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. Potentials to emit after controls for the project are 200.9 TPY NOx and 39.4 TPY $SO_2$ for the GE Option and 203.8 TPY NOx and 39.0 TPY $SO_2$ for the Siemens Option.

The modeling for NOx shows that receptor concentrations are below the NAAQS and further diminish within the modeling domain out to 10 kilometers to ensure the maximum concentrations are modeled. $SO_2$ was not modeled since the project's emissions are below the PSD threshold for $SO_2$. Since the $SO_2$ standards are extremely restrictive, being below the PSD significance levels and PSD major project thresholds would likely prevent the pollutants from impacting secondary formation significantly enough to result in a violation of the $PM_{2.5}$ standards, therefore $SO_2$ impacts to secondary $PM_{2.5}$ emissions are expected to be very minimal.

It is possible that some transformation into nitrates from this source may occur and be transported downwind. No peer-reviewed regulatory model presently exists to examine the impacts of an individual source of NOx. All photochemical models are regional scale and a source of this size would not show any measurable impact. Therefore, other available information from emissions inventories, meteorological analyses, and other modeling projects can be used to estimate the impact from this source. Further, the background concentrations and emissions of ammonia that participate in photochemical reactions to form secondary $PM_{2.5}$ are not expected to result in conversion of significant quantities of NOx emissions to secondary particles in the areas impacted by primary $PM_{2.5}$ emissions.

In order to determine the effect of NOx emissions on the $PM_{2.5}$ rate, the inter-pollutant ratios determined by EPA may be used. In EPA's guidance on the implementation of the $PM_{2.5}$ standard the EPA stated that for NOx the inter-pollutant ratio should be 100 tons of NOx per ton of $PM_{2.5}$ and 40 tons of $SO_2$ per ton of $PM_{2.5}$. Based on these inter-pollutant ratios, it is expected that $PM_{2.5}$ emissions would only increase by approximately 3 tons per year. This value is considered insignificant compared to the 144 tons of $PM_{2.5}$ – only a 2 percent increase over the existing $PM_{2.5}$ emissions that were modeled for the project.

To further the conclusion that the increase in ground level impacts from secondary $PM_{2.5}$ (NOx and $SO_2$ primarily) will not increase the $PM_{2.5}$ much at all, and will not create a NAAQS exceedance, one can look at the maximum $PM_{2.5}$ concentrations from the Project and perform a qualitative analysis of the increase in emissions. Secondary $PM_{2.5}$ impacts associated with precursor emissions are expected to be low near the emission release points where modeled concentrations associated with primary $PM_{2.5}$ emissions are highest, because there has not been enough time for the secondary chemical reactions to occur, while secondary $PM_{2.5}$ is normally found much farther out from the facility fenceline due to the time it takes to form as a secondary pollutant and the particle chacteristics. Since the high first high (H1H) was used to determine compliance with the NAAQS rather than the high $8^{th}$ high (H8H), the difference between these two impacts can be considered the impacts from secondary $PM_{2.5}$ formation. Using the EPA's inter-pollutant ratio of 100:1 (NOx to $PM_{2.5}$ ), which results in approximately 2 tons per year of $PM_{2.5}$, then secondary formation of $PM_{2.5}$ would have an estimated impact of 0.21 ug/m3 which is accounted for by using the H1H rather than the design value from the modeling.

Given emission levels from the facility and local emission inventories, no further analysis of secondary formation are necessary for this Project.

**6.13 Conclusion**

The modeling results shown in Table 6-6 (GE Option) and Table 6-11 (Siemens Option), demonstrate that no exceedances of the 1-hour and 8-hour CO, annual $NO_2$, and annual $PM_{10}$ modeling significance levels are predicted; no further modeling was required. A refined modeling analysis was conducted to demonstrate compliance with the PSD Class II Increments and NAAQS. There were no modeled Class II PSD Increment exceedances for $PM_{10}$ 24-hour and $PM_{2.5}$ annual and 24-hour averaging periods as shown in Table 6-7 (GE Option) and Table 6-12 (Siemens Option). Additionally, there were no modeled NAAQS exceedances for the $PM_{10}$ 24-hour averaging period as shown in Table 6-8 (GE Option) and Table 6-13 (Siemens Option).

While the $NO_2$ 1-hour NAAQS modeling predicted exceedances for both the GE and Siemens Options, it was demonstrated that the Mooreland Generating Station, including this project, is not significant at any of the modeled exceedances. Therefore, the Mooreland Generating Station (including the project) does not cause or contribute to the NAAQS exceedance.

Based on the Class I analysis, it was determined that the impacts from the proposed project for the GE Option and Siemens Option will not significantly impact the Wichita Mountains Wilderness and does not require further analysis.

The operation of the proposed project for the GE Option or Siemens Option will not cause or contribute to a significant degradation of ambient air quality. After examining the results of the model, it has been determined that the modeling requirements for CO, $NO_2$, and $PM_{10}/PM_{2.5}$ have been fulfilled, and no further modeling is required.

## SECTION VII. ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis requirement under OAC 252:100-8-35.2 includes the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis for the proposed Project at the Mooreland Generating Station.

### 7.1 Construction Impacts

Construction at the Mooreland Generating Station has the potential for short-term adverse effects on air quality in the immediate area around the site. Diesel fumes from construction vehicles and dust from site preparation and construction vehicle operation can affect local air quality during certain meteorological conditions. However, these instances are limited in time and area of effect.

The Woodward County area is in attainment or is unclassified for all criteria pollutants. Low sulfur fuel will be used for construction vehicles that use diesel fuel. Operation of these vehicles is not expected to significantly affect ambient air quality. During dry periods, fugitive dust may be minimized through the application of water to on-site roads used by construction equipment.

### 7.2 Vegetation Impacts

The following sections briefly describe the potential effects of $NO_2$, $SO_2$, CO, $PM/PM_{10}/PM_{2.5}$, and $CO_2e$ produced by the installation of the proposed natural gas combustion turbine project at the Mooreland Generating Station on the nearby vegetation. The potential effects of the air emissions to vegetation within the immediate vicinity of the Mooreland Generating Station were compared to scientific research examining the effects of pollution on vegetation. Damage to vegetation often results from acute exposure to pollution, but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are more associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning.[6]

[6] Hallgren, 1984; Hill and Littlefield, 1969; Mansfield and Freer-Smith, 1984.

### 7.2.1 Nitrogen Oxides

During fuel combustion, atmospheric and fuel-bound nitrogen is oxidized to nitrogen oxide (NO) and small amounts of $NO_2$.[7] The NO is photochemically oxidized to $NO_2$, which is then subsequently consumed during the production of ozone and peroxyacetyl nitrates (PANs). As with $SO_2$ emission research, $NO_2$ has been shown to deleteriously impact vegetation.[8] Typical leaf injury responses include interveinal necrotic blotches similar to $SO_2$ injury for angiosperms and red-brown distal necrosis in gymnosperms.[9] Injury threshold concentrations vary by species and dose, but are much higher than that of $SO_2$ as described above. In general, short-term, high concentrations of $NO_2$ are required for deleterious impacts on plants.[10] The injury threshold concentration for plants that are grown in Oklahoma, is 7,380 $\mu g/m^3$ for tomato (*Lycopersicon esculentum*) and annual sunflower (*Helianthus annuus*). A common, weedy plant found in Oklahoma is lamb's quarters (*Chenopodium album*); this species was not injured for two hours at concentrations of 1.9 $\mu g/m^3$ $NO_2$. Furthermore, short-term fumigations of approximately 1-hour, 20-hours, and 48-hours at $NO_2$ concentrations of 940 to 38,000 $\mu g/m^3$, 470 $\mu g/m^3$, and 3,000 to 5,000 $\mu g/m^3$, respectively, have been shown to deter photosynthesis in a number of herbaceous and woody plants.[11] Moreover, Taylor and McLean (1970),[12] in their review of $NO_2$ effects on vegetation, noted that long-term exposures of phytotoxic doses of $NO_2$ ranged from 280 to 560 $\mu g/m^3$. The maximum annual modeled values for the proposed Project at the Mooreland Generating Station are 0.94 $\mu g/m^3$ for the GE Option and 0.91 $\mu g/m^3$ for the Siemens Option. The maximum 1-hour $NO_2$ modeled values for the proposed Project at the Mooreland Generating Station are 86.43 $\mu g/m^3$ for the GE Option and 82.80 $\mu g/m^3$ for the Siemens Option. These levels are low, so it is highly unlikely that $NO_2$ emissions will impact vegetation adjacent to or surrounding the Mooreland Generating Station.

### 7.2.2 Synergistic Effects of Pollutants

Air pollutants are known to act in concert to cause injury to or decrease the functioning of plants.[13] Synergistic refers to the combined effects of pollutants when they are greater than is expected from the additive effect of the compounds. The inhibitory effects of $SO_2$ and $NO_2$[14], $NO_2$ and NO[15], $NO_2$ and ozone[16], and ozone and $SO_2$[17] have been reported in various short-term studies for crop plants (e.g., soybean, broad bean (*Vicia faba*), annual sunflower, and tomato) and various tree species that grow in Oklahoma [e.g., eastern cottonwood (*Populus deltoides*), sugar maple (*Acer saccharum*), white ash, and black oak (*Quercus velutina*)]. Concentrations of pollutants (80 to 981 $\mu g/m^3$) in these studies are higher than the concentrations predicted to occur near the Mooreland Generating Station. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near the Mooreland Generating Station.

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[7] Chang 1981
[8] Taylor et al. 1975; Heath 1980; Kozlowski and Constantinidou 1986; Darrall 1989
[9] Kozlowski and Constantinidou 1986
[10] Prinz and Brandt 1985
[11] Hill and Bennett 1970; Capron and Mansfield 1976; Smith 1981
[12] Taylor and McLean, 1970.
[13] *See* reviews of Reinert et al. 1975; Omrod 1982
[14] White et al. 1974; Wright et al. 1986
[15] Capron and Mansfield 1976
[16] Furakawa et al. 1984; Okana et al. 1985
[17] Costonis 1970, Carlson 1979; Jensen 1981; Omrod et al. 1981

### 7.2.3 Particulate Matter

Particulates have been shown to be detrimental to vegetation typically within the immediate vicinity of the source. The most obvious effect of particle deposition on vegetation is a physical smothering of the leaf surface. This will reduce light transmission to the plant and cause a decrease in photosynthesis. The maximum $PM_{10}$ 24-hour modeled values for the proposed Project at the Mooreland Generating Station are 14.92 $\mu g/m^3$ for the GE Option and 14.18 $\mu g/m^3$ for the Siemens Option. The maximum $PM_{2.5}$ 24-hour modeled values for the proposed Project at the Mooreland Generating Station are 14.92 $\mu g/m^3$ for the GE Option and 14.18 $\mu g/m^3$ for the Siemens Option. This level is low, so it is highly unlikely that $PM_{10}$ and $PM_{2.5}$ emissions will impact vegetation adjacent to the Mooreland Generating Station.

### 7.2.4 Carbon Monoxide

CO is not known to injure plants nor has it been shown to be taken up by plants. Consequently, no adverse impacts to vegetation at or near the Mooreland Generating Station are expected from CO stack emissions from the proposed combustion turbine project at the Mooreland Generating Station.

### 7.2.5 Carbon Dioxide

$CO_2$ is not known to injure plants. Long-term exposure to elevated $CO_2$ levels has shown to improve the efficiency of nutrient, water, and photosynthesis in some plants.[18] However, the improved efficiencies that result from elevated $CO_2$ levels may not necessarily result in greater yields for crop plants.[19] No adverse impacts to vegetation at or near the Mooreland Generating Station are expected from $CO_2$ stack emissions from the proposed Project.

### 7.3 Soil Impacts

Five soil types are mapped at, or in the immediate vicinity of, the Project site.[20] They include:

- Hardemon fine sandy loam, 1 to 3 percent slopes
- Mansic loam, 1 to 3 percent slopes
- Grandfield fine sandy loam, 1 to 3 percent slopes
- Eda loamy fine sand, 0 to 3 percent slopes and 3-8 percent slopes
- Eda-tivoli complex, 3 to 12 percent slopes

Sulfates and nitrates caused by $SO_2$ and $NO_2$ deposition on soil can be both beneficial and detrimental to soils depending on their composition. However, given the low expected deposition from the proposed turbine, operation of the proposed combustion turbine at the Mooreland Generating Station should not significantly affect the soils on-site or in the immediate vicinity.

### 7.4 Industrial, Residential, and Commercial Growth Impacts

The proposed Project at the Mooreland Generating Station is expected to increase employment in the area. The building phase will last approximately two years. Construction employment is expected to peak at approximately 150 skilled construction jobs. Projected employment, reflecting full-time jobs directly tied to the operation of the Mooreland Generating Station is

[18] Drake, Gonzalez-Meler, and Long 1997; Leakey, Ainsworth, Bernacchi, Rogers, Long, and Ort 2009

[19] Morgan, Bollero, Nelson, Dohleman, and Long 2005

[20] Natural Resources Conservation Service. 2012. *Soil Survey of Woodward County, Oklahoma*. Retrieved April 16, 2012 from http://soildatamart.nrcs.usda.gov/.

estimated to be 5 people at the facility. This will result in moderate amounts of secondary employment being created by the economic activity of the facility. In the immediate vicinity of the facility and as a result of the proposed Project at the Mooreland Generating Station, increased vehicular traffic is expected; however, these activities are not expected to significantly impact air quality.

An increase in the construction work may temporarily increase the number of people residing in the area for the construction phase. After construction is completed, many of the new employees are expected to already live in the area surrounding the Mooreland Generating Station. However, some new employees are expected to move into the area, with only a slight increase in the residential growth in the area. This small increase in new residences is not expected to have an impact on the air quality in the area.

Adding additional electricity to the grid in this area may increase industrial growth; however, it is unknown at this time how increasing available electrical power in this area may affect future industrial growth.

## 7.5 Visibility and Deposition Analysis

### 7.5.1 Class I Area Analysis

The nearest Class I area to the Mooreland Generating Station is the Wichita Mountains Wilderness Area in southwestern Oklahoma. The Wichita Mountains Wilderness Area is approximately 200 kilometers from the Mooreland site and is the only Class I area within 300 kilometers of the Mooreland site.

Following the most recent FLAG Workshop procedures (June 2010), the use of the Screening Procedure (Q/D) to determine if the Project could opt (screen) out of an Air Quality Related Value (AQRV) assessment for visibility and deposition with CALPUFF was made. Following the screening procedures in FLAG, the emissions of $NO_x$, $SO_2$, $PM_{10}/PM_{2.5}$, and $H_2SO_4$ mist were summed. No adjustment was made to reflect full time operation as the plant potential to emit is based on 8,760 hours of operation. The screening analysis for the GE Option is summarized below for the Wichita Mountains Wilderness Area, which is the closest Class I area:

- Q = sum($NO_x$+PM10/2.5+SOx+$H_2SO_4$)*(8760/8760) = 388.8
- $D_{\text{Wichita Mountains Wilderness}}$ = 200 km
- Q/D = 1.9 for Wichita Mountains Wilderness Area

The screening analysis for the Siemens Option is summarized below for the Wichita Mountains Wilderness Area, which is the closest Class I area:

- Q = sum($NO_x$+PM10/2.5+SOx+$H_2SO_4$)*(8760/8760) = 391.0
- $D_{\text{Wichita Mountains Wilderness}}$ = 200 km
- Q/D = 2.0 for Wichita Mountains Wilderness Area

In accordance with the FLAG Guidance, if Q/D is less than 10, then no AQRV analysis is required. Based on the ratio of Q/D for both the GE and Siemens Options, the Wichita Mountains Wilderness Class I Area does not require further analysis of AQRV. Thus, no CALPUFF analysis is anticipated for impacts to AQRVs. WFEC will seek confirmation as to this conclusion with the appropriate FLMs through the ODEQ.

**7.5.2 Class II Area Analysis**

The Mooreland Generating Station is located in a Class II area. With respect to visibility conditions around the facility, there are no known Class II screening visibility criteria that have been recommended at this time. A visibility analysis was performed for the GE Option and the Siemens Option on the two nearest Class II sensitive areas which are the Great Salt Plains State Park located approximately 103 kilometers northeast of the project near Jet, Oklahoma and the Black Kettle National Grassland located approximately 95 kilometers southwest of the project near Strong City, Oklahoma.

The visibility analysis was performed in accordance with the guidelines set forth in EPA-450/4-88-015, Workbook for Plume Visual Impact Screening and Analysis. Within the document, the model VISCREEN is recommended for plume visibility analysis. Several refinement levels of VISCREEN are described. The first-level VISCREEN analysis uses worst-case meteorological conditions (F-class stability, one meter per second wind speed). This level of screening results in the most conservative (worst-case) visibility results. If the plume visibility against the sky and terrain is below a level perceivable to the human eye, the visibility modeling is complete. Otherwise, a second-level VISCREEN analysis that uses actual meteorological data and refined particle characteristics can be performed. The second-level model will result in a more realistic visibility analysis. If this plume visibility still does not meet sky and terrain contrast levels, a third-level model may be required which adds more statistical analysis.

The first-level VISCREEN model was performed for the proposed Project at the Mooreland Generating Station. The inputs into the model included particulate matter, $NO_x$, primary $NO_2$, soot, and primary sulfate ($SO_4$). Annual particulate and $NO_x$ emissions were calculated for each operating scenario. The maximum annual particulate emission rate of 142.3 tons per year for the GE Option and 142.0 tons per year for the Siemens Option occurs when the proposed units operate 8,760 hours in combined-cycle mode; the maximum $NO_x$ emission rate of 201.1 tons per year for the GE Option and 204.0 tons per year for the Siemens Option occurs when the proposed units operate for 8,760 hours per year in combined-cycle mode. These maximum rates were used in the VISCREEN analysis.

According to the workbook, primary $NO_2$, soot, and primary $SO_4$ can be assumed to be zero except for very specific sources. Since the facility is not one of the specified sources, the emissions for the last three pollutants (primary $NO_2$, soot, and primary $SO_4$) are assumed to be zero. The next set of inputs into the first-level VISCREEN model considers the distance between the source, observer and area, and the background visual range. The distance between the source and observer for the two cases are 103 kilometers (distance to the Great Salt Plains State Park) and 95 kilometers (distance to the Black Kettle National Grassland). Background visibility was determined from the VISCREEN manual to be 40 kilometers.

The last inputs into the model are particle sizes, background ozone, plume-source-observer angle, stability, and wind speed. All of these inputs are automatically set if the default option is chosen. For the first-level analysis, the workbook tells the analyst to choose the default option, which sets the following particle sizes:

- background fine = 0.3 micrometer (μm) diameter, 1.5 gram per cubic centimeter ($g/cm^3$) density,
- background course = 6 μm diameter, 2.5 $g/cm^3$ density,

- plume particulate = 2 μm diameter, 2.5 $g/cm^3$ density,
- plume soot = 0.1 μm diameter, 2 $g/cm^3$ density, and
- plume primary sulfate = 0.5 μm diameter, 1.5 $g/cm^3$.

The background ozone is 0.04 ppm, the plume-source-observer angle is 11.25 degrees, the worst case atmospheric stability is an F stability class, and the worst case wind speed is one meter per second.

The VISCREEN model output compares the calculated Delta E and contrast from the plume to present default comparison values. Delta E is the color difference parameter used to characterize the perceptibility of the plume on a color difference between the plume and a viewing background such as the sky, a cloud, or a terrain feature. Color differences are due to differences in three dimensions: brightness (L*), color hue (a*), and saturation (b*). Delta E is calculated for several lines of sight. A green contrast analysis is also performed for various lines of sight using a green wavelength and contrasting the plume with the terrain and sky backgrounds. The critical E value is 2.0 and the green contrast value is 0.05 for Class I areas; however, there are currently no Class II screening visibility criteria for the state of Oklahoma.

The results of the first-level VISCREEN model are shown in Appendix G of the application. The visual results for the GE Option and the Siemens Option pass the Class I screening criteria at the two nearest Class II areas, Great Salt Plains State Park located approximately 103 kilometers away and the Black Kettle National Grassland located approximately 95 kilometers away.

### 7.6 Conclusion

Based upon the results presented in this section and additional supplemental information, it is concluded that the proposed Project at the Mooreland Generating Station will not have a significant adverse impact on the air quality, soils, vegetation, visibility and growth in the surrounding area.

## SECTION VIII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are duplicated below. Appropriate recordkeeping of activities indicated below with "*" is specified in the Specific Conditions.

1. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTU/hr heat input (commercial natural gas). The plant boiler, manufactured by Erie City Iron Works with a rated heat input of 2.4 MMBTUH, qualifies as an insignificant activity.

2. * Emissions from storage tanks constructed with a capacity less than 39,894 gallons that store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. There are four condensate tanks on site with capacities ranging from 100 to 300 barrels.

3. * Welding and soldering operations utilizing less than 100 lbs. of solder and 53 tons per year of electrodes.

4. * Surface coating operations which do not exceed a combined total usage of 60 gallons per month of coatings, thinners, and clean-up solvents at any one emissions unit.

5. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. Small amounts of solvent used for degreasing are applied to facility components using a rag.

6. * Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. The facility has not identified any activities that have the potential to emit more than 5 TPY (actual) of any criteria pollutant but it may have some in the future.

## SECTION IX. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the permit application, or developed from the applicable requirement.

Part 7 (PSD Requirements for Attainment Areas) [Applicable]
A PSD evaluation was completed for all regulated NSR pollutants for which the Project resulted in a significant emission increase and a significant net emissions increase ($NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, and $CO_2e$). Part 5 of this permit contains BACT analyses for those regulated NSR pollutants for which the Project will result in a significant emission increase and a significant net emissions increase. Part 6 of this permit contains air dispersion modeling analyses for each PSD-subject pollutant, and Part 7 of this permit contains additional impacts analyses for the PSD-subject pollutants. Emissions of lead, $SO_2$, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, fluorides, and $H_2SO_4$ mist resulting from this Project were not above their respective significance levels; therefore, these pollutants are not subject to PSD review.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Prohibition of Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
This subchapter specifies a PM emissions limitation of 0.6 lbs/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. Section 19-4 regulates emissions of PM from fuel-burning equipment. For fuel-burning equipment greater than 10 MMBTUH, this subchapter specifies a PM emission limitation based upon the heat input of the equipment and is calculated according to the following equations:

$E = 1.042808\ X^{-0.238561}$ – For Units > 10 MMBTUH but < 1,000 MMBTUH
$E = 1.6\ X^{-0.30103}$ – For Units > 1,000 MMBTUH but < 10,000 MMBTUH

Where:
E = allowable total particulate matter emissions in pounds per MMBTU and
X = the maximum heat input in MMBTU per hour.

| EU | MMBTUH | SC 19 Limit |
|---|---|---|
| A-1 | 756 | 0.2145 |
| A-2 | 1,620 | 0.1730 |
| A-3 | 1,755 | 0.1688 |
| A-4 | 3,300 | 0.1409 |
| B-1 | <5.0 | 0.6 |
| B-2 | 2.41 | 0.6 |
| B-3 | <10 | 0.6 |
| B-4 | <10 | 0.6 |

EU A-3 is subject to NSPS, Subpart D and is applicable to a PM emission limit of 0.1 lb/MMBTU which is more stringent and takes precedence. AP-42 (7/98), Section 1.4, Table 1.4-1, lists the total PM emissions for natural gas to be 7.6 lb/$MMft^3$ or about 0.00745 lb/MMBTU which is below all of the applicable limits. AP-42 (10/96), Section 3.3, Table 3.3-1 list emissions for diesel fired engines to be 0.31 lbs/MMBTU, which is in compliance. The permit requires the use of natural gas for all fuel-burning equipment except for the diesel fired emergency generator and the fire water pump to ensure compliance with Subchapter 19.

The maximum calculated emission rate from the combustion turbine plus the duct burner is approximately 0.01 lb/MMBtu for the combustion turbine under either the GE Option or the Siemens Option; therefore, the combustion turbine/duct burner will be in compliance with this subchapter.

The proposed cooling tower is subject to the requirements in OAC 252:100-19-12. Per this section, the cooling tower is limited to emissions determined in the following equation:

$$E = 4.10P^{0.67}$$

Where:

E = allowable total particulate matter emission rate in pounds per hour and
P = process weight rate in tons per hour

The cooling tower for the GE Option will be limited to 0.94 lb/hr per the rule and expected emissions are 0.7 lb/hr for all cells combined (which includes both filterable and condensable particulate emissions). The cooling tower for the Siemens Option will be limited to 1.01 lb/hr and the expected emissions from the cooling tower are 0.79 lb/hr for all cells combined (filterable plus condensable PM). The cooling tower (for either combustion turbine) will be in compliance with this rule.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case, shall the average of any six-minute period exceed 60% opacity. EU subject to an opacity limit under NSPS are exempt from the requirements of this subchapter. EU A-3 is subject to NSPS, Subpart D and is exempt from the requirements of this subchapter. The proposed combustion turbine will meet this opacity limit. When burning natural gas, there is very little possibility of exceeding the opacity standards, therefore no periodic observation is necessary.

Continuous monitoring of opacity (COM) is required for fluid bed catalytic cracking unit catalyst regenerators at petroleum refineries and fossil fuel-fired steam generators in accordance with 40 CFR Part 51, Appendix P. 40 CFR Part 51, Appendix P establishes a de minimis level of 250 MMBTUH for COM. The new turbine and duct burner have a heat input greater than 250 MMBTUH. Appendix P exempts from these requirements when gaseous fuel is the only fuel burned. Since the combustion turbine and duct burner will only burn natural gas they are exempt from the opacity monitor requirements.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 For new gas-fired fuel burning equipment, $SO_2$ emissions are limited to 0.2 lb/MMBtu heat input, based on a three-hour average. For new liquid-fired fuel-burning equipment, $SO_2$ emissions are limited to 0.8 lb/MMbtu heat input, based on a three-hour average. All three high-pressure boilers (A-1, A-2, A-3) were constructed prior to the effective date of this rule and are not subject to these requirements. $SO_2$ emissions associated with the proposed combustion turbine for both options are expected to be 0.002 lb/MMBtu during maximum operation, including duct firing; therefore, this unit will be in compliance with this regulation. $SO_2$ emissions associated with the emergency diesel generator and fire pump are expected to be 0.002 lb/MMBtu; therefore, these units will be in compliance with this regulation.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
$NO_X$ emissions are limited to 0.20 lb/MMBTU from all new gas-fired fuel-burning equipment with a rated heat input of 50 MMBTUH or greater. All three high-pressure boilers (A-1, A-2, A-3) were constructed prior to the effective date of this rule and are not subject to these requirements. The plant heating boiler has a heat input of 2.4 MMBTUH, which is below the 50 MMBTUH threshold. The new combustion turbine and duct burner are subject to this subchapter and will emit significantly less than 0.2 lb/MMBTU.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The four natural gas condensate tanks with capacities of 100, 190, 300, and 300 barrels are subject to the submerged fill requirement of this subchapter.
Part 3 requires VOC loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of

the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading and is not subject to this requirement.

Part 5 limits the VOC content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment which is exempt.

Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. Temperature and available air must be sufficient to provide essentially complete combustion.

Part 7 requires all effluent water separators, which receive water containing more than 200 gallons per day of any VOC, openings to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. There are no effluent water separators located at this facility.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]

This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]

This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

**The following Oklahoma Air Pollution Control Rules are not applicable to this facility:**

| | | |
|---|---|---|
| OAC 252:100-11 | Alternative Emissions Reduction | not requested |
| OAC 252:100-15 | Mobile Sources | not in source category |
| OAC 252:100-17 | Incinerators | not type of emission unit |
| OAC 252:100-23 | Cotton Gins | not type of emission unit |
| OAC 252:100-24 | Grain Elevators | not in source category |
| OAC 252:100-39 | Nonattainment Areas | not in area category |
| OAC 252:100-47 | Municipal Solid Waste Landfills | not in source category |

## SECTION X. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Total potential emissions for $NO_X$, CO, and $PM_{10}$ are greater than the major source threshold of 100 TPY for fossil fuel boiler facilities with total heat input exceeding 250 MMBTUH. A PSD evaluation was completed for all regulated NSR pollutants for which the Project resulted in a significant emission increase and a significant net emissions increase ($NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, and $CO_2e$). Part 5 of this permit contains BACT analyses for those regulated NSR pollutants for which the Project will result in a significant emission increase and a significant net emissions increase. Part 6 of this permit contains air dispersion modeling analyses for each PSD-subject pollutant, and Part 7 of this permit contains additional impacts analyses for the PSD-subject pollutants. Emissions of lead, $SO_2$, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, fluorides, and $H_2SO_4$ mist resulting from this Project were not above their respective significance levels; therefore, these pollutants are not subject to PSD review.

NSPS, 40 CFR Part 60 [Subparts D, IIII, KKKK and TTTT are Applicable]
Subpart D, HRSGs and duct burners regulated under Subpart KKKK are exempted from the requirements of 40 CFR Part 60 Subparts Da, Db, and Dc. Therefore Unit A-4 is exempt from this subpart.Units A-1 and A-2 are exempt from this subpart due to "grandfather" status. Unit A-3 is subject to this subpart.
Subpart K, Ka, Kb, VOL Storage Vessels. All of the tanks are below the de minimis amount of 40,000-gallons for Subparts K and Ka and 19,813-gallons for Subpart Kb.
Subpart GG, Stationary Gas Turbines. Stationary combustion turbines constructed after February 18, 2005 that are subject to Subpart KKKK are exempt from the requirements of Subpart GG. Therefore Unit A-4 is exempt from this subpart. Units A-1, A-2 and A-3 were all constructed prior to the applicability date and are therefore exempt from this subpart.

Subpart IIII, Subpart IIII applies to stationary compression ignition (CI) internal combustion engines (ICE) and the manufacturers or owners and operators of these engines as follows:

1. **Manufacturers** of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is 2007 or later for non-fire pump engines and the model year listed or later model years for fire pump engines (2008 or 2011).

2. **Owners and operators** of stationary CI ICE that commenced construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006 (non-fire pump engines), or manufactured as a National Fire Protection Agency fire pump engine after July 1, 2006.

Subpart IIII is assumed to be applicable to the emergency diesel generator. The emergency diesel generator will meet the definition of "emergency stationary internal combustion engine" under this subpart. Further, it is assumed the emergency diesel generator will be a 2007 model year or later. For purposes of estimating potential emissions associated with the emergency generator, WFEC is requesting a 100-hour per year non-emergency use limitation for required testing and maintenance.

Based on the size (horsepower) and use (emergency) and assuming WFEC purchases a certified model year 2007 or later CI ICE with a displacement that will likely be less than 30 liters per cylinder, the emergency diesel generator will be certified in accordance with the limits in 40 CFR 60.4202(a)(2), which refer to the limits in 40 CFR 89.112. As the emergency diesel generator will be greater than 560 kW and manufactured after 2006, Table 1 of 40 CFR 60.89.112(a) indicates the following applicable emission standards [subject to the same being included in a family emission limit in an averaging, banking, and trading program for which the emission standards in Table 2 of 40 CFR 89.112(d) are applicable]:

- 6.4 g/kW-hr for non-methane hydrocarbons (NMHC) plus $NO_x$,
- 3.5 g/kW-hr for CO, and
- 0.20 g/kW-hr for PM.

The emergency diesel generator will also be subject to the exhaust opacity limits in 40 CFR 89.113 limits:

- 20 percent during the acceleration mode
- 15 percent during the lugging mode
- 50 percent during the peaks in either the acceleration or lugging modes.

Since vendor data is not yet available for the emergency diesel generator, emissions for the purposes of dispersion modeling have been conservatively estimated based on AP-42, Chapter 3.4, and the above NSPS limits.

Compliance with this subpart will be shown by purchasing an engine certified to meet the applicable emission standards for the model year and maximum engine power depending on the date of purchase. WFEC will install an emergency diesel engine that meets the applicable emission standards based on the date that the unit will be installed.

Pursuant to 40 CFR 60.4207(b), owners and operators of CI ICE subject to Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel. If the emergency diesel engine that is purchased has a displacement of less than 30 liters per cylinder, then this rule will be applicable. As stated in 40 CFR 80.510(b), non-road diesel fuel must be limited to 15 ppm maximum sulfur content. The cetane index is limited to a minimum of 40 and the maximum aromatic content is limited to 35 volume percent.

WFEC will be subject to the applicable requirements of this rule for the emergency diesel generator.

Subpart KKKK Subpart KKKK is applicable to all stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005, with a heat input equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the higher heating value of fuel. Therefore, this NSPS is applicable to the proposed combustion turbine (both options) at the facility.

Pursuant to 40 CFR § 60.4320(a) and Table 1 to Subpart KKKK, the NSPS $NO_x$ limit applicable to the proposed combustion turbine, for natural gas combustion, is 15 ppm at 15 percent oxygen or 54 nanogram per Joule (ng/J) of useful output [0.43 pounds per megawatt-hour (lb/MW-hr)]. A $NO_x$ emission rate of 2 ppm is expected with the SCR for both options. In accordance with Subpart KKKK, compliance with the $NO_x$ emission limit will be demonstrated by conducting performance testing pursuant to § 60.4340(a), and, by installing, calibrating, maintaining, and operating a continuous monitoring system (i.e., continuous emission monitor (CEM) or continuous parameter monitor) in accordance with § 60.4340(b).

The NSPS $SO_2$ limit for the turbine is 0.90 lb/MW-hr gross output, **or** limit fuel so that any fuel combusted contains total potential sulfur emissions equal to or less than 0.060 pound $SO_2$ per million British thermal units (lb $SO_2$/MMBtu) heat input. Expected emissions of $SO_2$ during natural gas combustion are less than 0.023 lb/MW-hr for the GE Option and 0.022 lb/MW-hr for the Siemens Option. Emissions of $SO_2$ will be well below 0.90 lb/MW-hr; therefore, per 40 CFR § 60.4365(a), the permit will require the permitee to obtain and keep on record the fuel quality characteristics of the natural gas from the suppliers to document the natural gas contains 20 grains of sulfur or less per 100 standard cubic feet.

Subpart TTTT, (Proposed) Greenhouse Gas Emissions for Electric Utility Generating Units. Subpart TTTT, as proposed on April 13, 2012, (77 Federal Register 22392), if finalized as proposed, will establish Greenhouse Gas Emissions for Electric Utility Generating Units. With limited exception, the proposed standards will apply to all electrical utility generating units with a nameplate capacity of 25 MW or more that commence construction after April 13, 2012. This proposed standard includes a limit for natural gas-fired combined cycle combustion turbines (but excludes simple cycle combustion turbines). A natural gas-fired combined cycle turbine is limited to 454 kilograms of $CO_2$ per gross output in megawatt-hours (MW-hr) (454 kilograms per megawatt-hour (kg/MW-hr) or 1,000 lb/MW-hr) on a 12-operating month annual average basis. Unit A-4 will be subject to this subpart. Calculated $CO_2$ emissions from the combustion turbine under both options are less than 1,000 lb/MW-hr and will therefore comply with NSPS Subpart TTTT, as proposed.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene only affects process streams which contain more than 10% benzene by weight. All process streams at this facility are below this threshold.

NESHAP, 40 CFR Part 63 [Subpart ZZZZ Applicable]
Subpart Q, Industrial Process Cooling Towers. This subpart affects industrial process cooling towers and prohibits the use of chromium-based water treatment chemicals. The Project will not use chromium-based water treatment chemicals.

Subpart YYYY, Stationary Combustion Turbines. This subpart affects combustion turbines located at a major source that commenced construction or reconstruction on or after March 5, 2004. This facility is not a major source of HAP and this subpart does not apply.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1) Stationary RICE located at an area source;

2) The following Stationary RICE located at a major source of HAP emissions:
   i) 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
   ii) 4SLB stationary RICE with a site rating of < 250 brake HP;
   iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
   iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
   v) CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for engines subject to NSPS under this part. A stationary RICE located at an area source of HAP emissions is new if construction commenced on or after June 12, 2006. The new emergency generator engine is subject to this subpart and will comply with this subpart by complying with NSPS, Subpart IIII. Based on emission calculations, this facility is a minor source of HAP. This subpart is applicable to stationary RICE greater than 500 bhp located at area sources of HAP emissions. The 300-hp fire water pump engine (B-4) was constructed in 1987 and is therefore exempt from this subpart. The new emergency generator engine (B-3) is subject to this subpart based on line (1) above. All requirements have been incorporated into the permit.

Subpart JJJJJJ, Commercial and Institutional Boilers. This subpart affects new and existing boilers located at area sources of HAP, except for gas-fired boilers. Gas fired boilers are defined as any boiler that burns gaseous fuel not combined with any solid fuels, liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing under this definition shall not exceed a combined total of 48 hours during any calendar year. The boilers at this facility meet the definition of gas fired boilers and are not subject to this subpart.

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

The facility is subject to 40 CFR 75 (Acid Rain) requirements on the three high-pressure boilers and the proposed turbine will also be subject to Acid Rain requirements. Therefore, these units are exempt from additional CAM requirements.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not store any regulated substance above the applicable threshold limits. More information on this federal program is available at the web site: *http://www.epa.gov/ceppo/*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
The facility submitted a Phase II Monitoring Plan on December 15, 1995, and subsequently submitted a revised application on March 1, 1996. EPA issued a certificate of approval for the Continuous Emission Monitoring System (CEM) for EU A-1, A-2, A-3 in March 1999. A

separate Acid Rain Permit, No. 96-286-AR, was issued on April 16, 1999. The Acid Rain permit contained all of the Acid Rain requirements. An updated acid rain permit application will be submitted as required to include emission unit A-4.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
EU A-1, A-2, A-3 and A-4 are affected units and must meet the monitoring requirements of the Acid Rain Program whenever they are operated.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
<u>Subpart A</u> identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
<u>Subpart F</u> requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

Conditions are included in the standard conditions of the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

## SECTION XI. COMPLIANCE

### Tier Classification

This application has been determined to be **Tier II** based on the request for a significant modification of a Part 70 Source.

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land. Information on all permit actions is available for review by the public on the Air Quality section of the DEQ web page at: *http:/www.deq.state.ok.us*.

The applicant published the "Notice of Filing a Tier II Application" in "The Woodward News" a daily newspaper in Woodward County. The notice stated that the application was available for review at the Woodward Public Library. The applicant also published the "Notice of Tier II Draft Permit" in "The Woodward News" a daily newspaper in Woodward County. The notice stated that the draft permit was available for review at the Woodward Public Library. The draft permit was also available for public review on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*.

This facility is located within 50 miles of the border of Oklahoma and the states of Kansas and Texas; those states were notified of the draft permit. The "proposed" permit was submitted concurrently to EPA for a 45-day review period. There were no comments received.

**Fee Paid**

Part 70 significant modification application fee of $5,000 was submitted.

## SECTION XII. SUMMARY

The facility will be constructed and will operate as described in the permit application. Ambient air quality standards are not threatened at this site. Compliance and Enforcement concur with the issuance of this permit. Issuance of the construction permit is recommended.

**PERMIT TO CONSTRUCT**
**AIR POLLUTION CONTROL FACILITY**
**SPECIFIC CONDITIONS**

**Western Farmers Electric Cooperative**
**Mooreland Power Plant** **Permit Number 2008-302-C (M-1) PSD**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on August 22, 2012, with additional information on August 27, 2012, November 1, 2012, November 19, 2012, November 27, 2012, January 31, 2013 and March 13, 2013. The Evaluation Memorandum, dated June 26, 2013, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emissions limitations for each point:

**EUG A:**

| **Point Emissions** | **NOx** | **NOx** | **CO** | **CO** | **VOC** | **VOC** | **PM** | **PM** | **$SO_2$** | **$SO_2$** |
|---|---|---|---|---|---|---|---|---|---|---|
| **UNIT** | **lb/hr** | **TPY** | **lb/hr** | **TPY** | **lb/hr** | **TPY** | **lb/hr** | **TPY** | **lb/hr** | **TPY** |
| A-1 Babcock & Wilcox | -- | | -- | | -- | | -- | | -- | -- |
| A-2 Riley Stoker | -- | | -- | | -- | | -- | | -- | -- |
| A-3 Riley Stoker | 351.0 | 1537 | 144.5 | 633.0 | 9.5 | 41.5 | 13.1 | 57.3 | 90.3 | 395.5 |
| A-4a G.E. Turbine | 23.0 | 200.2 | 14.0 | 334.5 | 17.0 | 98.2 | 31.8 | 139.2 | 9.0 | 39.4 |
| A-4b Siemens Turbine | 23.8 | 203.1 | 14.5 | 336.3 | 17.0 | 98.4 | 31.6 | 138.6 | 8.9 | 39.0 |

EU A-1 and A-2 are grandfathered units. Either A-4a or A-4b will be constructed.
The Lb/hr emission limits applicable to EU A-4a and A-4b exclude start-up and shutdown emissions.

a. EU A-3 is subject to New Source Performance Standards, 40 CFR 60, Subpart D, and shall comply with all applicable requirements.
[§§ 60.40 through 60.46]

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases from EU A-3 that:
   i) contain particulate matter in excess of 43 nanograms per joule of heat input (0.1 lb/MMBTU) [§ 60.42(a)(1)]
   ii) exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. [§ 60.42(a)(2)]
   iii) contain nitrogen oxides (expressed as $NO_2$) in excess of 86 nanograms per joule of heat input (0.2 lb/MMBTU) [§ 60.44(a)(1)]

(2) The owner operator shall comply with the applicable provisions of § 60.45 Emission and Fuel Monitoring.

(3) The owner operator shall comply with the applicable provisions of § 60.46 Test Methods and Procedures.

**GE Option - Summary of BACT Results – Combustion Turbine**

| Equipment | Pollutant | Control | BACT Emission Rate | Averaging Period |
|---|---|---|---|---|
| GE Option - Natural Gas-Fired Combined Cycle Combustion Turbine with Duct Burner | $NO_x$ | Low $NO_x$ Burners<br>SCR | 2 ppmvd[A]<br>23.0 lb/hr[B] | 30-day |
| | CO | Oxidation Catalyst | 2 ppmvd[A]<br>14.0 lb/hr[B] | 3-hour |
| | $PM/PM_{10}/PM_{2.5}$ | Combustion Controls<br>Low Ash Fuels | 31.8 lb/hr[B] | 3-hour |
| | VOC | Oxidation Catalyst | 17.0 lb/hr[B] | 3-hour |
| | Greenhouse Gases | Use of natural gas as a fuel,<br>Monitoring and control of excess air, and<br>Efficient turbine design | 1,000 lb/MW-hr $CO_2$ | Annual |

[A] Concentration at 15 percent oxygen while operating at greater than 50 percent load. [B] Emissions at greater than 50% load.

**Siemens Option - Summary of BACT Results – Combustion Turbine**

| Equipment | Pollutant | Control | BACT Emission Rate | Averaging Period |
|---|---|---|---|---|
| Siemens Option - Natural Gas-Fired Combined Cycle Combustion Turbine with Duct Burner | $NO_x$ | Low $NO_x$ Burners<br>SCR | 2 ppmvd[A]<br>23.8 lb/hr[B] | 30-day |
| | CO | Oxidation Catalyst | 2 ppmvd[A]<br>14.5 lb/hr[B] | 3-hour |
| | $PM/PM_{10}/PM_{2.5}$ | Combustion Controls<br>Low Ash Fuels | 31.6 lb/hr[B] | 3-hour |
| | VOC | Oxidation Catalyst | 17.0 lb/hr[B] | 3-hour |
| | Greenhouse Gases | Use of natural gas as a fuel,<br>Monitoring and control of excess air, and<br>Efficient turbine design | 1,000 lb/MW-hr $CO_2$ | Annual |

[A] Concentration at 15 percent oxygen while operating at greater than 50 percent load. [B] Emissions at greater than 50% load.

b. EU A-4 shall be equipped with dry low-$NO_X$ burners. [OAC 252:100-8-34]

c. Emissions from EU A-4 and duct burner shall be controlled by a properly operated and maintained SCR and an oxidation catalyst. [OAC 252:100-8-34]

d. During startups and shutdowns, alternate short term emission limits apply to EU A-4. The short term emission limits for EU A-4 during startup and shutdown are shown below:

| Event | Maximum Duration (hr) | $NO_X$ Emissions (lbs/event) | CO Emissions (lbs/event) | VOC Emissions (lbs/event) | PM Emissions (lbs/event) |
|---|---|---|---|---|---|
| Startup | 4 | 573 | 1,363 | 163 | 66.9 |
| Shutdown | 1 | 48.3 | 151 | 23.5 | 6.6 |

e. To demonstrate compliance with the startup and shutdown emission limits for $NO_X$, the permittee shall calculate the total emissions during the event and compare it to the table above. Startup ends when the turbine reaches normal operating mode and the SCR is operational. Compliance with the start-up and shutdown CO, VOC, and PM emission limits shall be based on the duration of the event and compliance with the $NO_X$ emission limit. [OAC 252:100-8-6(a)(1)]

f. The turbine EU A-4 is subject to the NSPS for Stationary Combustion Turbines 40 CFR Part 60, Subpart KKKK and shall comply with all applicable requirements including but not limited to the following: [40 CFR § 60.4300 to § 60.4420]

<u>Introduction</u>

(1) §60.4300 What is the purpose of this subpart?

<u>Applicability</u>

(2) § 60.4305 Does this subpart apply to my stationary combustion turbine?

(3) § 60.4310 What types of operations are exempt from these standards of performance?

<u>Emission Limits</u>

(4) § 60.4315 What pollutants are regulated by this subpart?

(5) § 60.4320 What emission limits must I meet for nitrogen oxides ($NO_X$)?

(6) § 60.4325 What emission limits must I meet for $NO_X$ if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

(7) § 60.4330 What emission limits must I meet for sulfur dioxide ($SO_2$)?

<u>General Compliance Requirements</u>

(8) §60.4333 What are my general requirements for complying with this subpart?

<u>Monitoring</u>

(9) § 60.4335 How do I demonstrate compliance for $NO_X$ if I use water or steam injection?

(10) § 60.4340 How do I demonstrate continuous compliance for $NO_X$ if I do not use water or steam injection?

(11) § 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

(12) § 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

(13) § 60.4355 How do I establish and document a proper parameter monitoring plan?

(14) § 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

(15) § 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

(16) § 60.4370 How often must I determine the sulfur content of the fuel?
Reporting
(17) § 60.4375 What reports must I submit?
(18) § 60.4380 How are excess emissions and monitor downtime defined for $NO_X$?
(19) § 60.4385 How are excess emissions and monitoring downtime defined for $SO_2$?
(20) § 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
(21) § 60.4395 When must I submit my reports?
Performance Tests
(22) § 60.4400 How do I conduct the initial and subsequent performance tests, regarding $NO_X$?
(23) § 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
(24) § 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?
Definitions
(25) § 60.4420 What definitions apply to this subpart?

g. KKKK will require a CO stack test to show 3-hour average compliance.
h. When promulgated EU A-4 shall comply with applicable requirements of the NSPS for Greenhouse Gas Emissions for Electric Utility Generating Units 40 CFR Part 60, Subpart TTTT.

**EUG B General Equipment List**

| Point (EUG-EU) | Manufacturer | MMBTUH | KW | Serial Number |
|---|---|---|---|---|
| B-1* | Small Bldg. Heater | <5.0 | NA | |
| B-2* | Erie City Iron Works | 2.41 | NA | 96006 |
| B-3 | Emergency Gen. | - | 1,000 | TBD |
| B-4 | Cummins 300-hp Fire Pump | - | NA | 11482389 |

***** These units qualify insignificant activities since they have a rated heat input below 5 MMBTUH.

**EU B-3 Emergency Diesel Generator:** Emission limits and standards for EU B-3 include but are not limited to the following:

| EU | $NO_X$ | | CO | |
|---|---|---|---|---|
| | lb/hr | TPY | lb/hr | TPY |
| B-3 | 14.11 | 0.71 | 7.38 | 0.37 |

**Summary of BACT Results – Auxiliary Equipment**

| Equipment | Pollutant | Control | BACT Emission Rate |
|---|---|---|---|
| Emergency Diesel Generator | $NO_x$ | Combustion Control | 0.011 pound per horsepower-hour (lb/hp-hr) |
| | CO | Combustion Control | 0.006 lb/hp-hr |
| | $PM/PM_{10}/PM_{2.5}$ | Combustion Control | 0.44 lb/hr |
| | VOC | Combustion Control | 0.0007 lb/hp-hr |
| | Greenhouse Gases $CO_2e$ | Combustion Control | 81.2 tpy |
| Cooling Tower | $PM/PM_{10}/PM_{2.5}$ | High efficiency drift eliminators | 0.0005% Drift Eliminator 5.0 tons per year (GE) |
| | | | 0.0005% Drift Eliminator 5.6 tons per year (Siemens) |
| Diesel Tank | VOC | Fixed Roof Tank | 1.4 x $10^{-4}$ tons per year |

a. EU B-3 the Emergency Diesel Generator shall not operate more than 100 hours in any 12-month period. [OAC 252:100-8-6(a)(1)]

b. EU B-3 shall be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

c. EU B-3 the Emergency Generator shall only be fired with fuel oil with a maximum sulfur content of 0.0015% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once every calendar year. [OAC 252:100-31 & 8-34]

d. Replacement (including temporary periods of 6 months or less for maintenance purposes), of EU B-3 with an engine of lesser or equal emissions of each pollutant (in lbs/hr and TPY) are authorized under the following conditions:

   i. The permittee shall notify AQD in writing not later than 7 days in advance of the start-up of the replacement engine. Said notice shall identify the equipment removed and shall include the new engine make, model, and horsepower; date of the change, fuel usage, stack flow (ACFM), stack temperature ($^oF$), stack height (feet), stack diameter (inches), and pollutant emission rates (lbs/hr, and TPY) at maximum rated horsepower for the altitude/location and any change in emissions.

   ii. Replacement equipment and emissions are limited to equipment and emissions which do not subject the engine/turbine to an applicable requirement not already included in this permit.

   iii. The permittee shall calculate the net emissions increase resulting from the replacement to document that it does not exceed significance levels and submit the results with the notice required by Specific Condition 1, EU 4, (d). [OAC 252:100-8-6 (f)]

e. The Emergency Generator is subject to the NSPS for Stationary CI ICE, 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements: [40 CFR § 60.4200 - § 60.4219]

<u>What This Subpart Covers</u>

1. 60.4200 Am I subject to this subpart?

Emission Standards for Owners and Operators

2. 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
3. 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
4. 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators

5. 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators

6. 60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?
7. 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements

8. 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators

9. 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators

10. 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

General Provisions

11. 60.4218 What parts of the General Provisions apply to me?

f. The owner/operator shall comply with all applicable requirements of the National Emission Standards For Hazardous Air Pollutants (NESHAP), Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines (RICE), for Emergency Generator B-3 including but not limited to: [40 CFR Part 63, Subpart ZZZZ]

1. § 63.6580 What is the purpose of subpart ZZZZ?
2. § 63.6585 Am I subject to this subpart?
3. § 63.6590 What parts of my plant does this subpart cover?
4. § 63.6595 When do I have to comply with this subpart?
5. § 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
6. § 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

7. § 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?
8. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
9. § 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?
10. § 63.6605 What are my general requirements for complying with this subpart?
11. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
12. § 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?
13. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE located at an area source of HAP emissions?
14. § 63.6615 When must I conduct subsequent performance tests?
15. § 63.6620 What performance tests and other procedures must I use?
16. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
17. § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?
18. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
19. § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?
20. § 63.6645What notifications must I submit and when?
21. § 63.6650 What reports must I submit and when?
22. § 63.6655 What records must I keep?
23. § 63.6660 In what form and how long must I keep my records?
24. § 63.6665 What parts of the General Provisions apply to me?
25. § 63.6670 Who implements and enforces this subpart?
26. § 63.6675 What definitions apply to this subpart?

**<u>EU B-4</u>** **<u>Emergency Fire Pump:</u>**

A. EU B-4 the Fire Pump shall not operate more than 100 hours in any 12-month period.
[OAC 252:100-8-6(a)(1)]

B. EU B-4 shall be fitted with a non-resettable hour-meter.

[OAC 252:100-8-6(a)(3)]

C. EU B-4 shall only be fired with fuel oil with a maximum sulfur content of 0.0015% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once every calendar year.

[OAC 252:100-31 & 8-34]

**EUG C:** Storage tank VOC emissions are estimated based on existing equipment items but do not have a specific limitation

| Point (EUG-EU) | Contents | Capacity (barrels) |
|---|---|---|
| C-6 | Condensate | 100 |
| C-7 | Condensate | 190 |
| C-8 | Condensate | 300 |
| C-9 | Condensate | 300 |
| C-10 | Diesel | TBD |

a. The condensate tanks shall be fitted for submerged fill.

**EUG D. Cooling Towers.** EU D-1 through D-4 (ML-1 thru ML-4) are considered insignificant activities and are limited to the following standards:

| EU | Make/Model | No. of Towers |
|---|---|---|
| D-1 | Midwest Towers | 1 |
| D-2 | Midwest Towers | 1 |
| D-3 | Midwest Towers | 1 |
| D-4 | TBD | 1 |

a. The Cooling Towers shall be equipped with drift eliminators. [OAC 252:100-8-34]

2. Upon issuance of an operating permit the permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year).

3. The fuel-burning equipment with the exception of EU B-3 and EU B-4 shall be fired with pipeline grade natural gas. Compliance can be shown by the following methods: for pipeline grade natural gas, a current gas company bill; for other gaseous fuel, a current lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once each calendar year. [OAC 252:100-31]

4. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following: [40 CFR Part 75]

a. $SO_2$ actual emissions equal to or less than allowances held.
b. Report quarterly emissions to EPA per 40 CFR 75.
c. Conduct RATA tests per 40 CFR 75.
d. Maintain a QA/QC plan for the monitoring system.

5. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)]

a. Total natural gas usage (annual).
b. Operating hours for each boiler (annual).
c. Emissions data as required by the Acid Rain Program.
d. RATA test results.
e. For the fuel(s) burned, maintain the appropriate document(s) as described in Specific Condition No. 3 , Specific Condition No. 1 EUG B-3 c, and Specific Condition No. 1 EUG B-4 d.
f. Records of performance testing performed per SC. (8).
g. Records required by NSPS Part 60 Subparts D, IIII, KKKK and TTTT.
h. Records required by NESHAP Part 63 Subpart ZZZZ.

6. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations which qualify as Trivial Activities.
[OAC 252:100-8-6 (a)(3)(B)]

a. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTU/hr heat input (commercial natural gas). The plant boiler, (EU B-2) manufactured by Erie City Iron Works with a rated heat input of 2.4 MMBTUH, and the small building heater (EU B-1) qualify as insignificant activities.
b. Emissions from storage tanks constructed with a capacity less than 39,894 gallons that store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. There are four condensate tanks on site with capacities ranging from 100 to 300 barrels.
c. Welding and soldering operations utilizing less than 100 lbs. of solder and 53 tons per year of electrodes.
d. Surface coating operations which do not exceed a combined total usage of 60 gallons per month of coatings, thinners, and clean-up solvents at any one emissions unit.
e. For activities (except for trivial activities) that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions or a surrogate measure of the activity (annual).

7. When monitoring shows concentrations or emissions in excess of the limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions including during start-up, shutdown, and malfunction of air pollution control equipment. Start-up and shutdown emissions only need to be reported if they exceed the emissions limits listed in Specific Condition 1, EUG A(d). Requirements for periods of other excess emissions include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions. [OAC 252:100-9]

8. Within 60 days of achieving maximum power output from the new turbine generator set (A-4), not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with Subpart KKKK for the combustion turbine.

The permittee shall conduct $NO_X$, CO, $PM_{10}$, and VOC testing on the new turbine (A-4) at the 50% and 100% operating rates, with testing at the 100% turbine load to include testing at the 100% duct burner operating rate. $NO_X$ and CO testing shall also be conducted on the turbines at two additional intermediate points in the operating range, pursuant to 40 CFR §60.8. Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.4360.

The permittee shall conduct sulfuric acid mist testing on the new turbine and duct burner (A-4) at the 100% operating rate of both the turbine and duct burner. Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct formaldehyde testing on the new turbine (A-4) at the 50% and 100% operating rates, without the duct burner operating.

Performance testing shall be conducted while the new unit is operating within 10% of the specified testing rates. Testing protocols shall describe how the testing will be performed to satisfy the requirements of the applicable NSPS. The permittee shall provide a copy of the testing protocol, and notice of the actual test date, to AQD for review and approval at least 30 days prior to the start of such testing.

The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

| | |
|---|---|
| Method 1: | Sample and Velocity Traverses for Stationary Sources. |
| Method 2: | Determination of Stack Gas Velocity and Volumetric Flow Rate. |
| Method 3: | Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight. |
| Method 4: | Determination of Moisture in Stack Gases. |
| Method 5: | Determination of Particulate Emissions from stationary sources. |
| Method 8: | Sulfuric Acid Mist. |
| Method 10: | Determination of Carbon Monoxide Emissions from Stationary Sources. |
| Method 6C | Quality Assurance procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10. |
| Method 20: | Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines. |
| Method 25/25A: | Determination of Non-Methane Organic Emissions From Stationary Sources. |

Method 202: Determination of $PM_{10}$ condensable Emissions
Method 320: Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

9. The permittee shall apply for a modification of its current Title V operating permit and an Acid Rain permit within 180 days of operational start-up.

# PART 70 PERMIT

**AIR QUALITY DIVISION**
**STATE OF OKLAHOMA**
**DEPARTMENT OF ENVIRONMENTAL QUALITY**
**707 N. ROBINSON, SUITE 4100**
**P.O. BOX 1677**
**OKLAHOMA CITY, OKLAHOMA 73101-1677**

**Permit No. 2008-302-C (M-1) PSD**

**Western Farmers Electric Cooperative**

**having complied with the requirements of the law, is hereby granted permission to construct /modify the Moreland Power Plant located in Section 27, Township 23N, Range 19W, Woodward County, Oklahoma, subject to Standard Conditions dated July 21, 2009, and Specific Conditions both attached.**

**In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.**

**Director,**
**Air Quality Division**

**Issuance Date**

**MAJOR SOURCE AIR QUALITY PERMIT**
**STANDARD CONDITIONS**
**(July 21, 2009)**

## SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

## SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

## SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:
(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter ($PM_{10}$). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

## SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

## SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

## SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

## SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

## SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. A complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

## SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby. [OAC 252:100-8-6 (a)(6)]

## SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege. [OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

## SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit. [OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment. [OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

## SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a “grandfathered source,” as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

## SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

**SECTION XIV. EMERGENCIES**

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.
[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

**SECTION XV. RISK MANAGEMENT PLAN**

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

**SECTION XVI. INSIGNIFICANT ACTIVITIES**

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below.

Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

## SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

## SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

## SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter.

[OAC 252:100-13]

(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

## SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane

(Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

## SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).
(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

## SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

Mr. Gerald Butcher, Environmental Supervisor
Western Farmers Electric Cooperative
P.O. Box 429
Anadarko, OK 73005-0429

Re: Construction Permit No. 2008-302-C (M-1) PSD
Mooreland Generating Station
Woodward County, Oklahoma

Dear Mr. Butcher:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to the certain standard and specific conditions which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact our office at (405) 702-4100.

Sincerely,

Charles Stockford, P.E.
Existing Source Permits Section
**AIR QUALITY DIVISION**

Enclosures: